2003 Safety-Net Cost Recovery Adjustment Clause
Final Proposal

Documentation for Chapter 6
Risk Analysis

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RISK ANALYSIS DOCUMENTATION

INTRODUCTION

The Federal Columbia River Power System (FCRPS), operated on behalf of the ratepayers of the Pacific Northwest (PNW) by the Bonneville Power Administration (BPA) and other Federal agencies, faces many uncertainties during the remainder of the Fiscal Year (FY) 2002-2006 rate period. Among these uncertainties are variable hydro conditions and volatile market prices. In order to provide a high probability of making its Treasury payments on time and in full during the rate period, BPA performs the Risk Analysis.

In this Risk Analysis, BPA identifies key risks, models their relationships, and then analyzes their impacts on net revenues (revenues less expenses). BPA subsequently evaluates in the ToolKit Model the impact that certain risk mitigation measures have on reducing its net revenue risk so that BPA can develop rates that cover all its costs and provide a high probability of making its Treasury payments on time and in full during the rate period.

The Risk Analysis focuses upon operating risks - variations in economic conditions, load, and generation resource capability – and their impact on BPA's revenues and expenses. These operating risks are modeled in RiskMod. RiskMod is a computer simulation model that calculates firm and surplus energy revenues, balancing power purchase expenses, Fish Cost Contingency Fund (FCCF) credits, and 4(h)(10)(C) credits under various load, resource, and market price conditions to estimate BPA's operational net revenue risk.

The output from RiskMod yields a distribution of net revenue deviations that are input into the ToolKit Model. The ToolKit Model uses the net revenue data to test the effectiveness of implementing various risk mitigation measures in order to provide a high probability of BPA making its Treasury payments on time and in full during the rate period.

RiskMod uses the simulation methodology in the @RISK computer software package to assess the impacts of a distribution of risk factors on net revenues. RiskMod quantifies the operating risks associated with loads and resources performance for California, the PNW, and the Federal system, in addition to those risks associated with natural gas prices.

This chapter describes the operation of RiskMod and its quantification of net revenue risks. Chapter 7 of this Study Documentation describes how the net revenue results of the Risk Analysis are used in the ToolKit Model.

6. OPERATIONAL RISK ANALYSIS MODEL (RISKMOD)

6.1 RiskMod

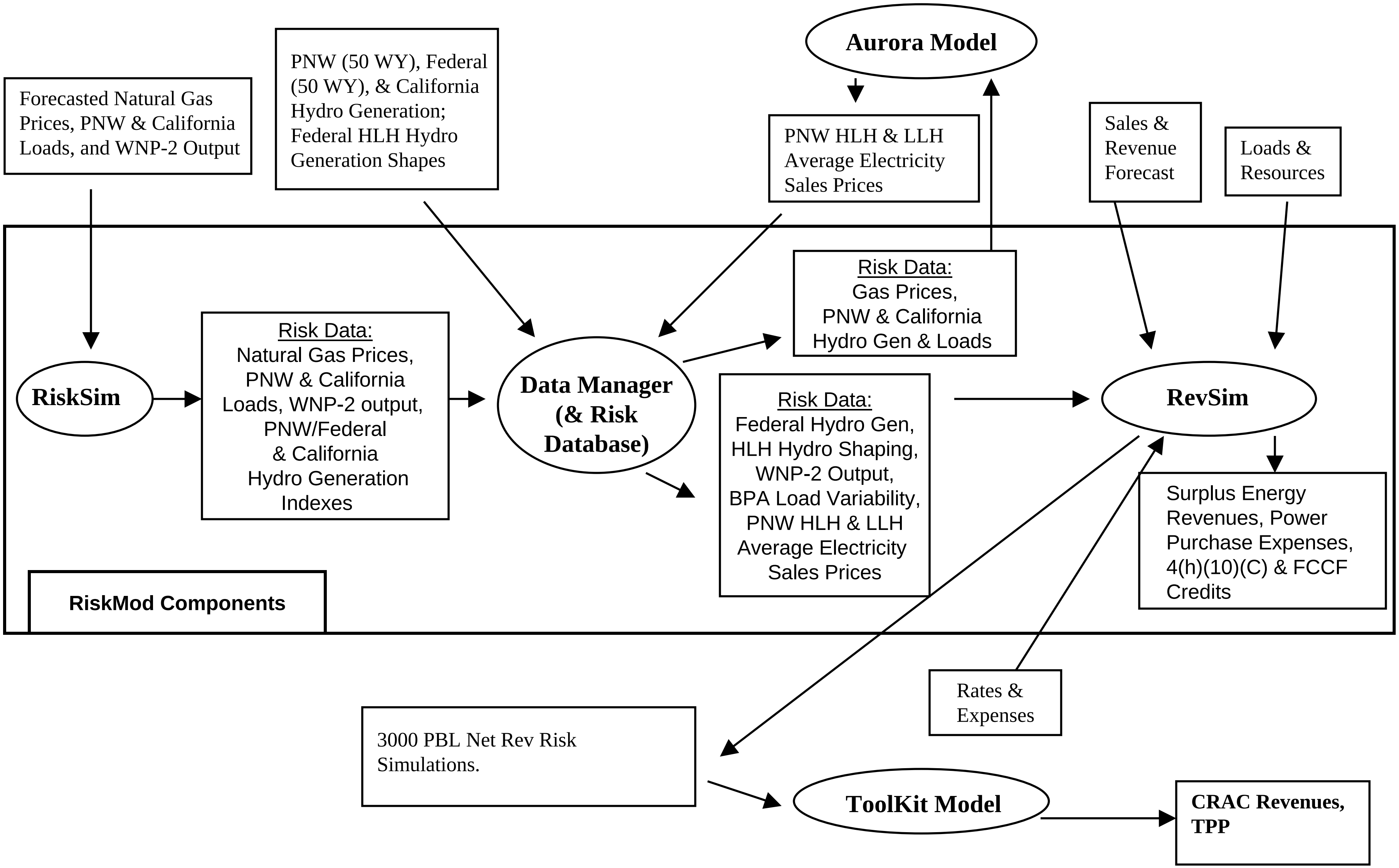
The RiskMod Model is comprised of a set of risk simulation models collectively referred to as RiskSim; a set of computer programs that manages data referred to as Data Manager; and RevSim, a model that calculates net revenues. Variations in monthly loads, resources, and natural gas prices are simulated in RiskSim. Monthly electricity prices for the simulated loads, resources, and natural gas prices are estimated by the AURORA Model. *See* Chapter 4 of the Study. The Data Manager facilitates the format and movement of data that flow to and from RiskSim, RevSim, and AURORA. RevSim uses risk data from RiskSim, electricity prices from AURORA, load and resource data from the Loads and Resources Study (*see* Chapter 2 of the Study), various revenues and rates from the Revenue Forecast (s*ee* Chapter 5 of the Study), and expenses from the Revenue Recovery (*see* Chapter 3 of the Study) to estimate net revenues. Annual average surplus energy revenues, purchased power expenses, section 4(h)(10)(C) credits, and FCCF credits calculated by RevSim are used in the Revenue Forecast. Net revenues estimated for each simulation by RevSim are input into the ToolKit Model to calculate CRAC revenues. The processes and interactions between RiskMod and other models and studies are depicted in Graph 6.1.

6.2 Risk Simulation Models (RiskSim)

To quantify the effects of operational risks, BPA has developed risk simulation models that combine logic, econometrics, and probability distributions to quantify the ordinary operational risks that BPA faces. Econometric modeling techniques are used to capture the dependency of values through time. Parameters for the probability distributions are developed from historical data. The values sampled from each probability distribution reflect their relative likelihood of occurrence and are deviations from the base case values used in the AURORA Model and the Revenue Forecast. *See* Chapters 4 and 5 of the Study.

The monthly output from these risk simulation models were accumulated into a computer file to form a risk database which contains values lower than, higher than, or equal to the forecasted values used in the AURORA Model and the Revenue Forecast. *Id.* Loads, resources, and natural gas price risk data for each simulation were input into the AURORA Model to estimate monthly Heavy Load Hour (HLH) and Light Load Hour (LLH) electricity prices. The prices estimated by AURORA were then downloaded into the risk database and a consistent set of loads, resources, and electricity prices were used to calculate net revenues in RevSim. The risk models are run for 3000 simulations to produce monthly risk data for FY 2003-2006 for this rate filing.

Graph 6.1: RiskMod Risk Analysis Information Flow



6.3 @RISK Computer Software

The risk simulation models developed to quantify operational risks were developed in the @RISK computer software package. This software is an add-in computer package to Microsoft Excel and is available from Palisade Corporation. @RISK allows statisticians to develop models incorporating uncertainty in a spreadsheet environment. Uncertainty is incorporated by specifying the type of probability distribution that best reflects the risk, providing the necessary parameters required for developing the probability distribution, and letting @RISK sample values from the probability distributions based on the parameters provided. The values sampled from the probability distributions reflect their relative likelihood of occurrence. The parameters required for appropriately capturing risk are not developed in @RISK, but are developed in analyses external to @RISK.

6.4 Operational Risk Factors

In the course of doing business, BPA manages risks that are unique to operating a hydro system as large as the FCRPS. The variation in hydro generation due to the volume of water supply from one year to the next can be substantial. BPA also faces other traditional operational risks that increase BPA's risk exposure, including the following: load variability due to load growth and weather; nuclear plant (CGS) performance; and variability in electricity prices due to load, resource, and natural gas price variability. The following is a discussion of the major risk factors included in RiskMod.

6.5 PNW and Federal Hydro Generation Risk Factors

Federal hydro generation risk was incorporated into RiskMod to account for the impact that various Federal hydro generation levels and HLH and LLH hydro generation shaping capability have on the quantity of energy that BPA has to buy and sell during HLH and LLH periods. PNW hydro generation risk is incorporated into the Risk Analysis to account for the impact that various PNW hydro generation levels have on monthly HLH and LLH electricity prices estimated by the AURORA Model. PNW and Federal hydro generation risk are incorporated into the Risk Analysis in different ways for FY 2004-2006 than FY 2003.

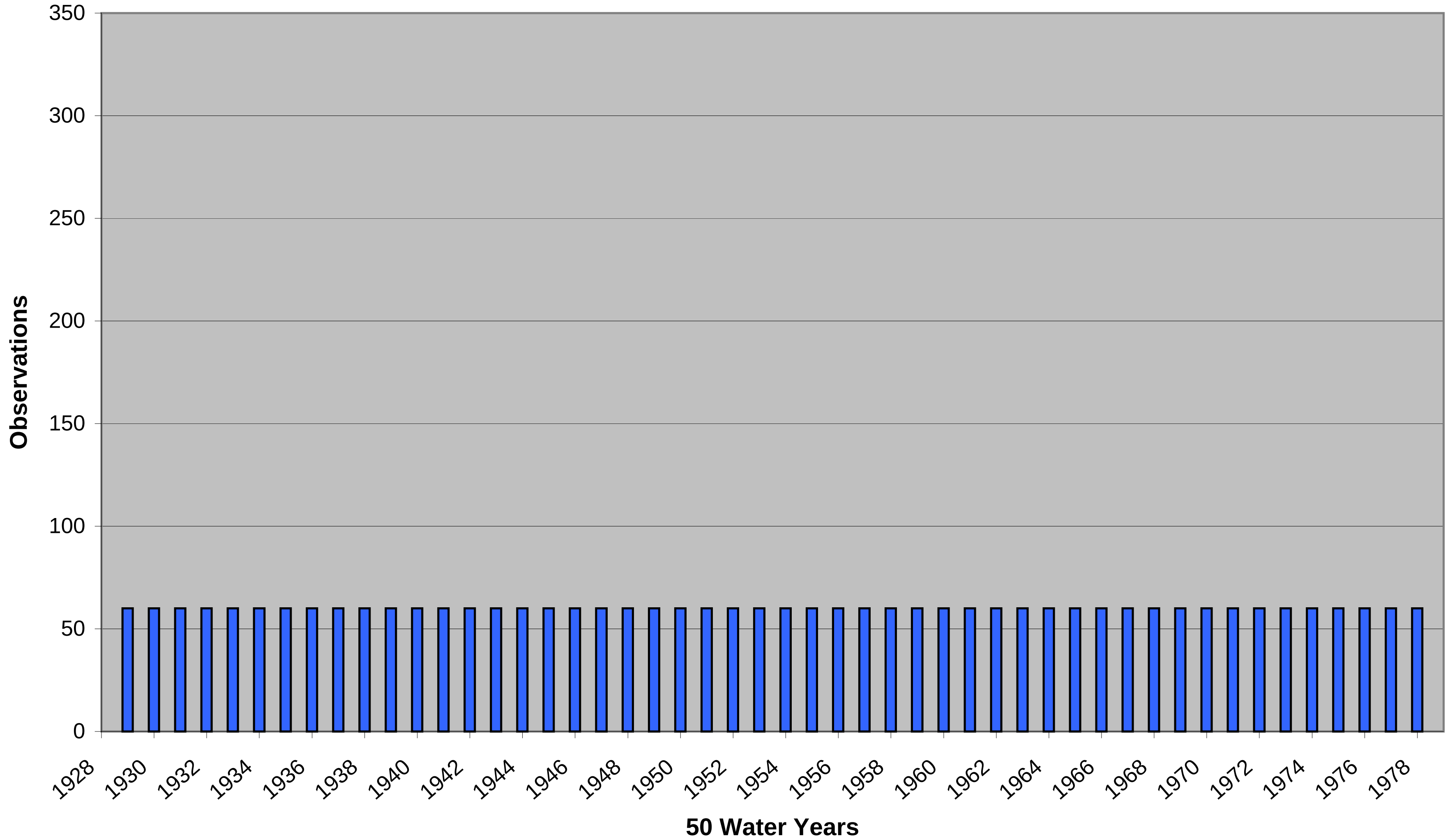
6.5.1 Modeling FY 2004-2006 Hydro Risk. For FY 2004-2006, Federal and PNW hydro generation risk were accounted for in the Risk Analysis by inputting into RiskMod and AURORA monthly Federal and PNW hydro generation data for each of the historical 50 water years (1929-1978) developed from running a continuous study in the HydroSim Model. *See* Hydro Regulation component of the Loads and Resources Study (Chapter 2 of the Study), regarding HydroSim, continuous study, and 50 water years. The term "continuous study" refers to calculating hydro generation data sequentially over all 600 months of the 50 water year period. Developing hydro generation data in such a continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 50 water year period. For FY 2004, additional hydro generation adjustments were made to each of the 50 water year data from the continuous study for FY 2004 to reflect the outlook that storage levels on the Federal Columbia River Power System may not refill in FY 2003. *See* Chapter 2 of the Study, regarding FY 2004 hydro generation adjustments.

A consistent set of monthly Federal and PNW hydro generation data for hydro operations in FY 2004 are randomly sampled, by water year, from tables containing hydro generation values for each of the 50 water years for 12 months of the year (50 X 12 tables). The 50 X 12 tables were derived from 50 X 14 tables by averaging hydro generation data for the first and second half of April and August. The ability of the FCRPS to shape average monthly hydro generation into HLH hydro generation, for each water year, is incorporated into RiskMod by selecting from a 50 X 12 table of HLH ratios produced by the Hourly Operating and Scheduling Simulator

(HOSS) Model. *See* Chapter 2 of the Study, regarding HOSS. The HLH ratios used are based on the water year sampled for hydro generation and these ratios reflect the portion of average energy that can be shaped into heavy load hours. Given the HLH ratios from HOSS, LLH ratios are calculated in RevSim. *See* Chapter 2 of this Study Documentation, for tables of FY 2004-2006 Federal and PNW hydro generation data, along with HLH ratios from HOSS and hydro generation adjustments for FY 2004.

6.5.2 Sampling FY 2004 – FY 2006 Hydro Generation. Federal and PNW hydro generation variability is modeled in the Risk Analysis by randomly sampling, in the @RISK computer software, each of the 50 water years (1929-1978) and using the associated hydro generation data in the same continuous manner that the data are developed by HydroSim when performing a continuous study. The random selection of the initial water year (for FY 2004) is accomplished by sampling real values ranging from 1929-1978 from a uniform probability distribution in a risk simulation model and subsequently converting each number to the nearest integer values (whole numbers). Given the initial water year, the corresponding monthly Federal and PNW hydro generation data and the HOSS HLH hydro generation ratios for that water year are selected for the first year (FY 2004). The uniform probability distribution was selected for modeling hydro generation risk because it appropriately assigns equal probability to each of the 50 water years being sampled. Graph 6.2 reports the number of times that each of the 50 water years were sampled from a uniform probability distribution for 3000 simulations. As shown in this graph, each of the 50 water years was sampled 60 times.

Graph 6.2: Number of Times PNW and Federal Hydro Generation for the 50 Water Years were Sampled for FY's 2004-06 Based on 3000 Sampled Values



After an initial water year is selected for FY 2004 for a given simulation, hydro generation data for a sequential set of three water years, starting with the water year selected for FY 2004, are selected from water years 1929-1978. When the end of the 50 water years is reached (at the end of water year 1978), monthly hydro generation data for water year 1929 is subsequently used. Thus, if a simulation starts with water year 1977, the simulation will use water years 1977 and 1978, as well as water year 1929, for a total of three sequential water years. This approach was used so that each of the 50 water years was sampled an equal number of times. Using Federal and PNW hydro generation data in this continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 50 water years of hydro generation data.

6.5.3 Modeling FY 2003 Hydro Risk. For FY 2003, Federal and PNW hydro generation risk were accounted for in the Risk Analysis by inputting into RiskMod and AURORA monthly Federal and PNW hydro generation data for each of the historical 50 water years (1929-1978) developed from running a refill study in the HydroSim Model. *See* Hydro Regulation component of the Loads and Resources Study (Chapter 2 of the Study), regarding HydroSim, refill study, and 50 water years. The term "refill study" refers to calculating hydro generation data based on updated information about reservoir levels. Developing hydro generation data in such this manner provides more accurate data regarding near-term hydro generation risk.

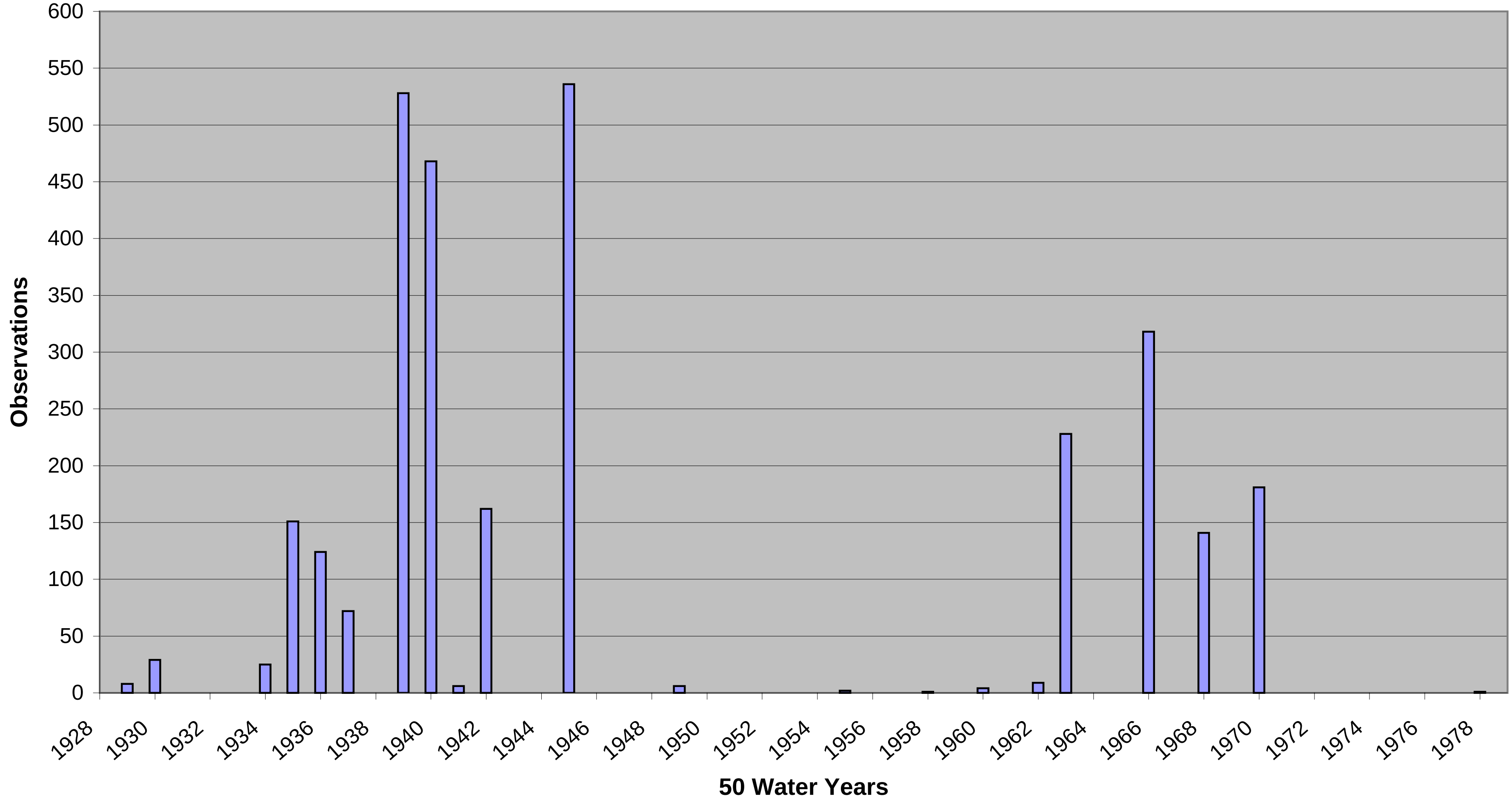
Consistent sets of monthly Federal and PNW hydro generation data for hydro operations in FY 2003 from the refill study are sampled from tables containing hydro generation values for each of the 50 water years for 12 months of the year (50 X 12 tables). The 50 X 12 tables were derived from 50 X 14 tables by averaging hydro generation data for the first and second half of April and August. The ability of the FCRPS to shape average monthly hydro generation into HLH hydro generation, for each water year, is incorporated into RiskMod by selecting from a 50 X 12 table of HLH ratios produced by the HOSS Model. The HLH ratios used are based on the water year sampled for hydro generation and these ratios reflect the portion of average energy that can be shaped into heavy load hours. Given the HLH ratios from HOSS, LLH ratios are calculated in RevSim. *See* Chapter 2 of this Study Documentation, for tables of FY 2003 Federal and PNW hydro generation data, along with HLH ratios from HOSS.

For FY 2003, the hydro generation data for each of the 50 water years were probability-weighted in RiskMod so that the sampled hydro generation data yielded results consistent with the 2003 April-September runoff volume forecast (May Final Forecast) by the Northwest River Forecast Center. *See* Hydro Regulation component of the Loads and Resources Study (Chapter 2 of the Study) and Chapter 2 of this Study Documentation, for tables of FY 2003 Federal and PNW hydro generation data, along with the associated probability weights.

6.5.4 Sampling FY 2003 Hydro Generation. FY 2003 Federal and PNW hydro generation variability is modeled in the Risk Analysis using the @Risk computer software. This task was accomplished by developing a discrete probability distribution in @Risk that reflected the probability of the April-September streamflow amounts (in MAF) for each of the 50 water years occurring in FY 2003, consistent with the 2003 April-September runoff volume forecast (May Final Forecast) by the Northwest River Forecast Center. The probabilities of various hydro generation amounts was determined by sampling values from 1929 to 1978 (50 WY) at their respective probability weights from the discrete probability distribution and selecting the corresponding monthly Federal and PNW hydro generation data and the HOSS HLH hydro generation ratios for each water year. Under this approach, several of the water years had probability weights of zero.

The discrete probability distribution was selected for modeling hydro generation risk for FY 2003 because it easily and accurately accommodates the exact probability weights associated with the 2003 April-September runoff volume forecast. Graph 6.3 reports the number of times

Graph 6.3: Number of Times PNW and Federal Hydro Generation for the 50 Water Years were Sampled Using WY Weights for FY 2003 Based on 3000 Sampled Values



that each of the 50 water years were sampled for FY 2003 from the discrete probability distribution for 3000 simulations.

6.5.5 Use of PNW Hydro Generation Risk in AURORA. Variability in PNW hydro generation is incorporated into the AURORA Model by calculating (via the Data Manager), from monthly PNW hydro generation data for each of the 50 water years, PNW annual energy to capacity ratios (using the total capacity value for all of the PNW in the AURORA Model), calculating PNW monthly to annual hydro generation ratios, and inputting this data into the AURORA Model. *See* Chapter 4 of the Study, regarding the AURORA Model. These sets of ratios are used by AURORA to calculate first the annual, and then the monthly hydro generation for each of the three regions (Oregon/Washington, Idaho, Montana) for the PNW in AURORA. This process results in the sum of the hydro generation for the three regions in AURORA being equal to the PNW hydro generation.

6.6 PNW and BPA Loads Risk Factors

PNW load uncertainty is incorporated into the Risk Analysis to account for the impact that PNW load uncertainty has on monthly HLH and LLH electricity prices--which impacts BPA's surplus energy revenues and power purchase expenses. This impact is accounted for by inputting into the AURORA Model various PNW load values and having it estimate the associated HLH and LLH electricity prices. *See* Chapter 4 of the Study, regarding the AURORA Model.

BPA load uncertainty is incorporated into the Risk Analysis to account for the impact that monthly PF load variability has on PF revenues, surplus energy revenues, and power purchase expenses. This impact is accounted for by inputting into RevSim various monthly load variability values that modify the amount of PF loads served by BPA.

6.6.1 PNW and BPA Load Variability. Only monthly PNW load variability is modeled in the PNW Load Risk Model. BPA monthly load variability is derived such that the same percentage changes in PNW loads are used to quantify BPA load variability.

The PNW Load Risk Model is designed to incorporate forecasted monthly load data from the AURORA Model such that, when no risk is being simulated, the forecasted monthly loads match the sum of the forecasted loads for the three regions (Oregon/Washington, Idaho, and Montana) that comprise the PNW in the AURORA Model. This process results in the simulated loads reflecting variability in loads relative to the forecasted loads used in AURORA. *See* Chapter 4 of the Study, regarding the AURORA Model.

Variability in monthly BPA loads is derived from simulated PNW loads by dividing simulated loads by forecasted PNW loads to obtain ratios that are values relative to 1.00 (when the simulated loads equal the forecasted loads). For instance, a value of 1.05 translates into a 5 percent increase in PNW loads and into a 5 percent increase in BPA loads.

PNW (and indirectly BPA) load variability is modeled in the PNW Load Risk Model such that annual load growth variability and monthly load swings due to weather conditions are both accounted for in one PNW load variability factor. This task is accomplished by first simulating annual load growth for years from 2003-2006 and then, subsequently, simulating the impact of monthly load swings due to weather on the simulated monthly loads that include load growth.

6.6.2 PNW and BPA Annual Load Growth Risk. PNW (and indirectly BPA) annual load growth risk is modeled using a random-walk technique. This quantitative method simulates various annual average load levels through time with the starting point for simulating annual average load in a given year being the annual average load level from the previous year. Under this method, simulated annual average loads randomly increase and decrease through time from the annual average load level of the prior year with the results including outcomes that represent periods of strong load growth, weak load growth, and vacillating positive and negative load growth.

Input data from the AURORA Model used in the PNW Load Risk Model are the following: (1) annual average 2002 PNW load; (2) forecasted annual load growth for 2003-2006; and (3) monthly load shaping factors (values relative to 1.00) that were derived for use in AURORA by dividing historical monthly loads by historical annual average loads. *See* Chapter 4 of the Study, regarding the AURORA Model. Inputting the data used by the AURORA Model allows the PNW Load Risk Model to replicate the forecasted monthly PNW loads in AURORA.

Load growth variability is incorporated into the PNW Load Risk Model by sampling values from standard normal distributions (normal distributions with a mean of zero and a standard deviation of one) in @RISK, multiplying the sampled values by an annual load growth standard deviation, and adding the simulated positive and negative values to the annual load level of the prior year. The values sampled from the standard normal distribution are in terms of the number of positive or negative standard deviations. Variability in monthly loads due to load growth risk is derived by multiplying variable annual loads by deterministic monthly load shape factors. The annual load growth standard deviation used in the PNW Load Risk Model is 2.4 percent, which was derived from historical Western Electricity Coordinating Council (WECC, formerly called the WSCC) load data from 1982-1998 for the Northwest Power Pool Area. The source of this data was a publication by the WECC titled, 10-Year Coordinated Plan Summary 1999-2008, Planning and Operation for Electric System Reliability, Western Systems Coordinating Council, October 1999, at 60. The historical WECC load data and the annual load growth standard deviation calculations by BPA are reported in Tables 6.1 and 6.2.

Table 6.1: Historical WSCC Load Data (Calendar Year)

	Thousands of GWh						aMW				
Year	Northwest Power Pool Area	Rocky Mountain Power Area	Arizona New Mexico So. Nevada Power Area	California Mexico Power Area	WSCC Total		Northwest Power Pool Area	Rocky Mountain Power Area	Arizona New Mexico So. Nevada Power Area	California Mexico Power Area	WSCC Total
1982	234.8	31.28	42.72	188.0	496.8		26,804	3,571	4,877	21,461	56,712
1983	235.3	31.81	44.08	188.0	499.2		26,861	3,631	5,032	21,461	56,985
1984	250.9	33.09	46.70	205.2	535.9		28,642	3,777	5,331	23,425	61,175
1985	257.3	35.40	50.64	209.7	553.0		29,372	4,041	5,781	23,938	63,132
1986	253.4	34.82	51.46	216.3	556.0		28,927	3,975	5,874	24,692	63,468
1987	262.4	35.36	**63.42**	**214.6**	575.8		29,954	4,037	7,240	24,498	65,728
1988	280.2	37.03	**67.48**	**223.3**	608.0		31,986	4,227	7,703	25,491	69,408
1989	291.4	38.02	**71.25**	**229.1**	629.8		33,265	4,340	8,134	26,153	71,892
1990	301.1	38.49	**74.54**	**236.7**	650.8		34,372	4,394	8,509	27,021	74,296
1991	305.2	38.44	**75.71**	**230.6**	650.0		34,840	4,388	8,643	26,324	74,195
1992	307.6	39.99	**77.90**	**236.7**	662.2		35,114	4,565	8,893	27,021	75,592
1993	312.8	40.55	**80.42**	**235.6**	669.4		35,708	4,629	9,180	26,895	76,412
1994	316.3	42.05	**86.05**	**243.7**	688.1		36,107	4,800	9,823	27,820	78,550
1995	318.3	43.42	**87.66**	**240.5**	689.9		36,336	4,957	10,007	27,454	78,753
1996	334.2	43.92	**94.72**	**248.7**	721.5		38,151	5,014	10,813	28,390	82,368
1997	332.1	47.08	**98.53**	**256.9**	734.6		37,911	5,374	11,248	29,326	83,860
1998	342.9	48.07	**97.36**	**254.6**	742.9		39,144	5,487	11,114	29,064	84,809

Note: For the reason describe below, California load growth variability was calculated using data from 1987-98.

Prior to 1997, the Southern Nevada reporting-area data were included in the California sub-area data.
The Arizona-New Mexico-Southern Nevada Power Area and California-Mexico Power Area data, prior to 1987,
have not been adjusted for the Southern Nevada reporting-area change

Table 6.2: PNW and California Annual Load Variability Computations

Year	Northwest Power Pool Area	Change From Prior Year 1982-98		Year	California Mexico Power Area	Change From Prior Year 1987 98
1982	26,804			1987	24,498	
1983	26,861	0.002		1988	25,491	0.041
1984	28,642	0.066		1989	26,153	0.026
1985	29,372	0.026		1990	27,021	0.033
1986	28,927	-0.015		1991	26,324	-0.026
1987	29,954	0.036		1992	27,021	0.026
1988	31,986	0.068		1993	26,895	-0.005
1989	33,265	0.040		1994	27,820	0.034
1990	34,372	0.033		1995	27,454	-0.013
1991	34,840	0.014		1996	28,390	0.034
1992	35,114	0.008		1997	29,326	0.033
1993	35,708	0.017		1998	29,064	-0.009
1994	36,107	0.011				
1995	36,336	0.006				
1996	38,151	0.050				
1997	37,911	-0.006				
1998	39,144	0.033				
	Avg	**0.024**			**Avg**	**0.016**
	StDev	**0.024**			**StDev**	**0.024**
	Min	**-0.015**			**Min**	**-0.026**
	Max	**0.068**			**Max**	**0.041**

6.6.3 PNW and BPA Load Risk Due to Weather Conditions. Monthly PNW (and indirectly BPA) load variability due to weather conditions is quantified by first sampling values from standard normal distributions in @RISK, then multiplying the sampled values by monthly PNW load standard deviations, and finally adding the resulting positive and negative values to the simulated loads after load growth.

The monthly PNW load standard deviations are derived from utility-specific, monthly historical daily load standard deviations and 2005 forecasted loads for PNW utilities used as input data in PMDAM when performing the MCA in the 1996 rate case (*see* MCA Study Documentation, WP-96-FS-BPA-04A, Part 2 of 2; pages 305 and 257). This derivation is accomplished by calculating composite, load-weighted, monthly load standard deviations from utility-specific, daily load standard deviations (for the 12 months of the year) and annual average load data.

6.6.4 Derivation of PNW/BPA Monthly Load Variability Due to Weather Conditions. BPA assumes, for rate setting purposes, that daily weather patterns over the course of a month are independent and that each day of a given month has the same daily load standard deviation. Accordingly, BPA used the following statistical equation to derive monthly load standard deviations from daily load standard deviations for each month. The statistical equation for calculating the standard deviation for the average of "n" number of independent random variables is the following:

$$\sigma_{\bar{x}} = \frac{\sigma_x}{\sqrt{n}}$$

Where:

$\underline{\sigma_x}$ is the standard deviation for all independent random variables

$\overline{n}$ is the number of independent random variables

In the case of BPA's analysis, the number of independent random variables is the number of days in a month and the standard deviation for all the independent random variables is the daily load standard deviations for each month. The PNW monthly load standard deviations for each month are derived by inserting values for the number of days in each month and the daily load standard deviations for each month into the equation above.

Table 6.3 contains the calculations performed to derive PNW monthly load standard deviations from daily load standard deviations for each month. These monthly load standard deviations are input into the PNW Load Risk Model to quantify monthly load variability due to weather. Table 6.4 contains a copy of the PNW Load Risk Model. Results from this risk model are shown in Graph 6.4 for the 5^{th}, 50^{th}, and 95^{th} percentiles.

6.6.5 Use of Simulated PNW Loads in AURORA. The HLH and LLH electricity prices associated with changes in PNW monthly loads are estimated in the AURORA Model by inputting PNW load data simulated by the PNW Load Risk Model. This process involves calculating (via the Data Manager) monthly load ratios (monthly loads divided by the annual average loads) from monthly and annual load data simulated by the PNW Load Risk Model and then inputting the monthly ratios and annual average energy loads into the AURORA Model for each simulation. *See* Chapter 4 of the Study, regarding the AURORA Model. These data are input into AURORA to calculate annual and monthly loads for each of the three PNW regions (Oregon/Washington, Idaho, and Montana) in AURORA. This process results in the sum of the loads for the three PNW regions in AURORA being equal to the simulated PNW loads from the PNW Load Risk Model.

Table 6.3: Derivation of Load-Weighted, Monthly Load Standard Deviations for PNW

PNW

		Loads CY 2005	Daily Load Standard Deviations Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PGE	PGEFRM	2057	0.10	0.10	0.08	0.09	0.08	0.08	0.11	0.08	0.09	0.09	0.09	0.10
PP&L	PPLFRM	2462	0.12	0.13	0.10	0.13	0.12	0.10	0.16	0.11	0.12	0.12	0.12	0.13
OIOU	OIOFRM	2772	0.07	0.09	0.05	0.07	0.06	0.07	0.08	0.06	0.07	0.06	0.07	0.07
GPUB	GPUFRM	2827	0.08	0.08	0.07	0.08	0.09	0.07	0.08	0.07	0.08	0.09	0.08	0.09
BPA	BPAFRM	3740	0.09	0.09	0.06	0.07	0.06	0.05	0.06	0.06	0.07	0.08	0.09	0.10
OIOU	PSPL	2673	0.09	0.10	0.07	0.10	0.08	0.06	0.07	0.06	0.07	0.09	0.09	0.09
GPUB	COPOSN	1499	0.09	0.08	0.06	0.08	0.08	0.08	0.14	0.04	0.07	0.07	0.07	0.10
BPA	DSIFRM	1061	0.02	0.01	0.01	0.02	0.01	0.02	0.01	0.01	0.05	0.01	0.01	0.01
BPA	DSI2Q	2122	0.02	0.01	0.01	0.02	0.01	0.02	0.01	0.01	0.05	0.01	0.01	0.01
BPA	DSINFM	0	0.02	0.01	0.01	0.02	0.01	0.02	0.01	0.01	0.05	0.01	0.01	0.01
Total PNW		**21213**												

		Loads CY 2005	Daily Load Variances Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PGE	PGEFRM	2057	0.0100	0.0100	0.0064	0.0081	0.0064	0.0064	0.0121	0.0064	0.0081	0.0081	0.0081	0.0100
PP&L	PPLFRM	2462	0.0144	0.0169	0.0100	0.0169	0.0144	0.0100	0.0256	0.0121	0.0144	0.0144	0.0144	0.0169
OIOU	OIOFRM	2772	0.0049	0.0081	0.0025	0.0049	0.0036	0.0049	0.0064	0.0036	0.0049	0.0036	0.0049	0.0049
GPUB	GPUFRM	2827	0.0064	0.0064	0.0049	0.0064	0.0081	0.0049	0.0064	0.0049	0.0064	0.0081	0.0064	0.0081
BPA	BPAFRM	3740	0.0081	0.0081	0.0036	0.0049	0.0036	0.0025	0.0036	0.0036	0.0049	0.0064	0.0081	0.0100
OIOU	PSPL	2673	0.0081	0.0100	0.0049	0.0100	0.0064	0.0036	0.0049	0.0036	0.0049	0.0081	0.0081	0.0081
GPUB	COPOSN	1499	0.0081	0.0064	0.0036	0.0064	0.0064	0.0064	0.0196	0.0016	0.0049	0.0049	0.0049	0.0100
BPA	DSIFRM	1061	0.0004	0.0001	0.0001	0.0004	0.0001	0.0004	0.0001	0.0001	0.0025	0.0001	0.0001	0.0001
BPA	DSI2Q	2122	0.0004	0.0001	0.0001	0.0004	0.0001	0.0004	0.0001	0.0001	0.0025	0.0001	0.0001	0.0001
BPA	DSINFM	0	0.0004	0.0001	0.0001	0.0004	0.0001	0.0004	0.0001	0.0001	0.0025	0.0001	0.0001	0.0001
Total PNW		**21213**												
Number of Days Per Month			31	28	31	30	31	30	31	31	30	31	30	31
Weighted Daily Load Variances			**0.0072**	**0.0080**	**0.0043**	**0.0069**	**0.0058**	**0.0045**	**0.0085**	**0.0044**	**0.0062**	**0.0065**	**0.0068**	**0.0082**
Weighted Daily Load Standard Deviations			**0.0849**	**0.0894**	**0.0654**	**0.0829**	**0.0758**	**0.0669**	**0.0921**	**0.0661**	**0.0784**	**0.0807**	**0.0822**	**0.0903**
Monthly Load Standard Deviations			**0.0153**	**0.0169**	**0.0118**	**0.0151**	**0.0136**	**0.0122**	**0.0165**	**0.0119**	**0.0143**	**0.0145**	**0.0150**	**0.0162**

Table 6.4: PNW Load Risk Model for 2003 - 2006

PNW Load Variability

PNW Load Growth Uncertainty:

Forecasted Calendar Year (2002) Annual Average PNW Loads	21,221
Forecasted PNW Load Growth for 2002; Source: Aurora	0.00%
Forecasted PNW Load Growth for 2003; Source: Aurora	2.61%
Forecasted PNW Load Growth for 2004; Source: Aurora	1.73%
Forecasted PNW Load Growth for 2005; Source: Aurora	1.97%
Forecasted PNW Load Growth for 2006; Source: Aurora	1.80%
Load Growth Std Dev; Source: PMDAM	2.40%

Estimated Base Case Loads		*Std Normal Dist*
CY 2002	21,221	*0.0*
CY 2003	21,775	*0.0*
CY 2004	22,152	*0.0*
CY 2005	22,588	*0.0*
CY 2006	22,995	*0.0*

Load Growth Dev from any specified forecasted load level	
CY 2002	*21221*
CY 2003	*21775*
CY 2004	*22152*
CY 2005	*22588*
CY 2006	*22995*

PNW Load Variability Due to Load Growth Uncertainty

Calendar Year 2003

	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	Jul '03	Aug '03	Sep '03	Oct '03	Nov '03	Dec '03	Average
Average Annual PNW Loads (Average Energy in aMW)	21775	21775	21775	21775	21775	21775	21775	21775	21775	21775	21775	21775	
PNW Monthly Load Shapes (Source: AURORA)	1.138	1.108	1.010	0.940	0.921	0.935	0.959	0.942	0.911	0.940	1.063	1.139	
Simulated Monthly PNW Loads (Average Energy in aMW)	24785	24123	21997	20471	20063	20355	20872	20502	19843	20461	23156	24792	21,785 aMW

PNW Load Variability Due to Load Growth and Weather Uncertainty

	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	Jul '03	Aug '03	Sep '03	Oct '03	Nov '03	Dec '03	
PNW Loads after Load Growth (Average Energy in aMW)	24785	24123	21997	20471	20063	20355	20872	20502	19843	20461	23156	24792	21,785 aMW
Monthly Load Standard Deviation (Derived, Via Simulation, from Daily Load Standard Deviations in PMDAM)	1.53%	1.69%	1.18%	1.51%	1.36%	1.22%	1.65%	1.19%	1.43%	1.45%	1.50%	1.62%	
Random PNW Loads (Average Energy in aMW)	*24,785*	*24,123*	*21,997*	*20,471*	*20,063*	*20,355*	*20,872*	*20,502*	*19,843*	*20,461*	*23,156*	*24,792*	21,785 aMW

Table 6.4: PNW Load Risk Model for 2004 (Continued)

PNW Load Variability

PNW Load Variability Due to Load Growth Uncertainty

Calendar Year 2004	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	Jul '04	Aug '04	Sep '04	Oct '04	Nov '04	Dec '04	Average
Average Annual PNW Loads (Average Energy in aMW)	22152	22152	22152	22152	22152	22152	22152	22152	22152	22152	22152	22152	
PNW Monthly Load Shapes (Source: AURORA)	**1.138**	**1.108**	**1.010**	**0.940**	**0.921**	**0.935**	**0.959**	**0.942**	**0.911**	**0.940**	**1.063**	**1.139**	
Simulated Monthly PNW Loads (Average Energy in aMW)	25213	24541	22378	20826	20410	20707	21233	20856	20186	20815	23557	25221	**22,162 aMW**

PNW Load Variability Due to Load Growth and Weather Uncertainty

	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	Jul '04	Aug '04	Sep '04	Oct '04	Nov '04	Dec '04	
PNW Loads after Load Growth (Average Energy in aMW)	25213	24541	22378	20826	20410	20707	21233	20856	20186	20815	23557	25221	**22,162 aMW**
Monthly Load Standard Deviation (Derived, Via Simulation, from Daily Load Standard Deviations in PMDAM)	1.53%	1.69%	1.18%	1.51%	1.36%	1.22%	1.65%	1.19%	1.43%	1.45%	1.50%	1.62%	
Random PNW Loads (Average Energy in aMW)	***25,213***	***24,541***	***22,378***	***20,826***	***20,410***	***20,707***	***21,233***	***20,856***	***20,186***	***20,815***	***23,557***	***25,221***	**22,162 aMW**

Table 6.4: PNW Load Risk Model for 2005 (Continued)

PNW Load Variability

PNW Load Variability Due to Load Growth Uncertainty

Calendar Year 2005

	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	Jul '05	Aug '05	Sep '05	Oct '05	Nov '05	Dec '05	Average
Average Annual PNW Loads (Average Energy in aMW)	22588	22588	22588	22588	22588	22588	22588	22588	22588	22588	22588	22588	
PNW Monthly Load Shapes (Source: AURORA)	**1.138**	**1.108**	**1.010**	**0.940**	**0.921**	**0.935**	**0.959**	**0.942**	**0.911**	**0.940**	**1.063**	**1.139**	
Simulated Monthly PNW Loads (Average Energy in aMW)	25710	25024	22819	21236	20812	21115	21652	21267	20583	21225	24021	25718	**22,598 aMW**

PNW Load Variability Due to Load Growth and Weather Uncertainty

	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	Jul '05	Aug '05	Sep '05	Oct '05	Nov '05	Dec '05	
PNW Loads after Load Growth (Average Energy in aMW)	25710	25024	22819	21236	20812	21115	21652	21267	20583	21225	24021	25718	**22,598 aMW**
Monthly Load Standard Deviation (Derived, Via Simulation, from Daily Load Standard Deviations in PMDAM)	1.53%	1.69%	1.18%	1.51%	1.36%	1.22%	1.65%	1.19%	1.43%	1.45%	1.50%	1.62%	
Random PNW Loads (Average Energy in aMW)	***25,710***	***25,024***	***22,819***	***21,236***	***20,812***	***21,115***	***21,652***	***21,267***	***20,583***	***21,225***	***24,021***	***25,718***	**22,598 aMW**

Table 6.4: PNW Load Risk Model for 2006 (Continued)

PNW Load Variability

PNW Load Variability Due to Load Growth Uncertainty

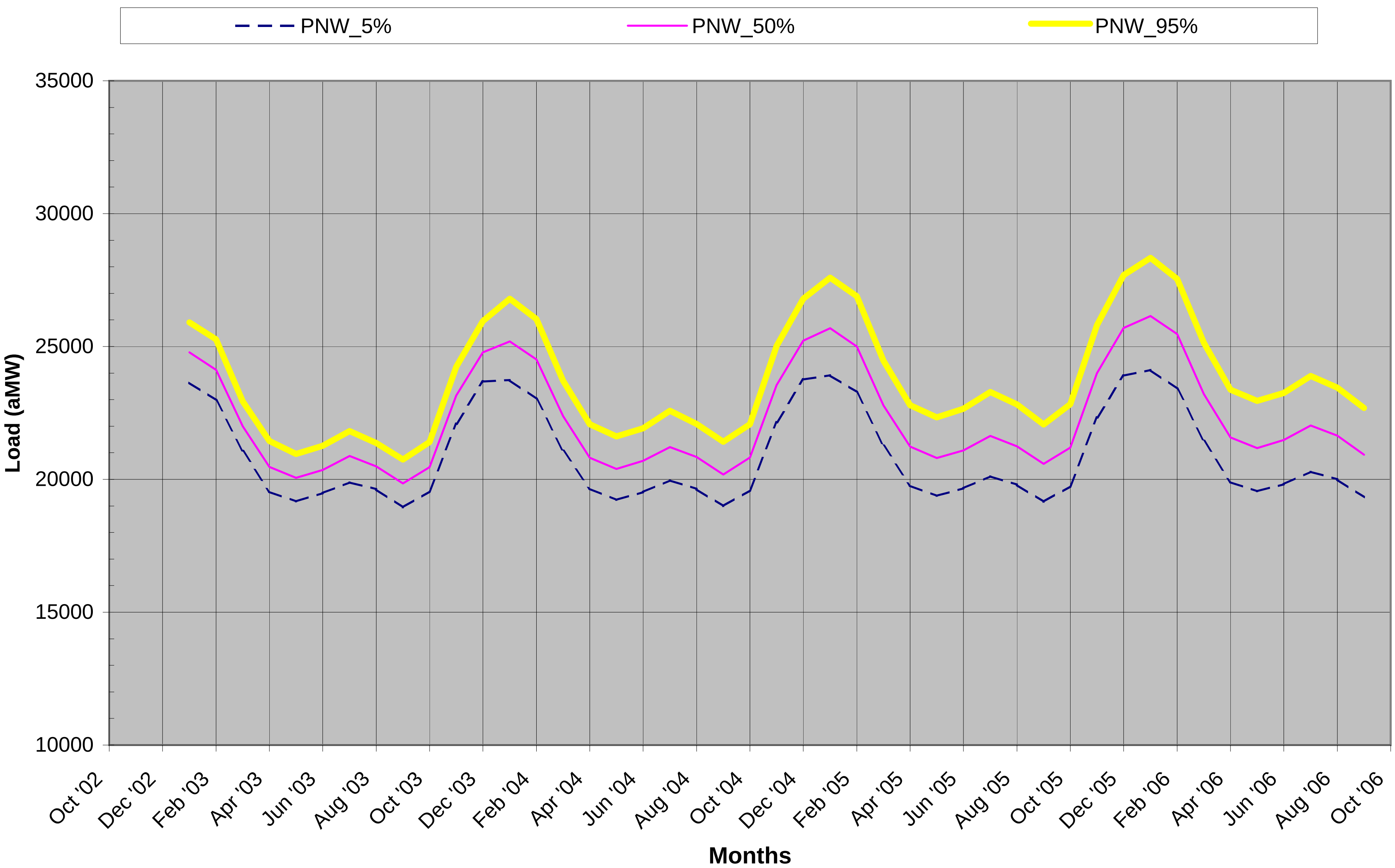
Calendar Year 2006

	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	Average
Average Annual PNW Loads (Average Energy in aMW)	22995	22995	22995	22995	22995	22995	22995	22995	22995	22995	22995	22995	
PNW Monthly Load Shapes (Source: AURORA)	**1.138**	**1.108**	**1.010**	**0.940**	**0.921**	**0.935**	**0.959**	**0.942**	**0.911**	**0.940**	**1.063**	**1.139**	
Simulated Monthly PNW Loads (Average Energy in aMW)	26173	25474	23230	21618	21187	21495	22041	21650	20954	21607	24453	26181	**23,005 aMW**

PNW Load Variability Due to Load Growth and Weather Uncertainty

	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	
PNW Loads after Load Growth (Average Energy in aMW)	26173	25474	23230	21618	21187	21495	22041	21650	20954	21607	24453	26181	**23,005 aMW**
Monthly Load Standard Deviation (Derived, Via Simulation, from Daily Load Standard Deviations in PMDAM)	1.53%	1.69%	1.18%	1.51%	1.36%	1.22%	1.65%	1.19%	1.43%	1.45%	1.50%	1.62%	
Random PNW Loads (Average Energy in aMW)	***26,173***	***25,474***	***23,230***	***21,618***	***21,187***	***21,495***	***22,041***	***21,650***	***20,954***	***21,607***	***24,453***	***26,181***	**23,005 aMW**

Graph 6.4: Simulated PNW Loads for 2003 - 2006



6.7 California Hydro Generation Risk Factor

California hydro generation risk is incorporated into the Risk Analysis to account for the impact that variability in California hydro generation has on monthly HLH and LLH electricity prices--which impacts BPA's surplus energy revenues and power purchase expenses.

6.7.1 Modeling Hydro Risk. California hydro generation risk for FY 2003-2006 is incorporated into the Risk Analysis by sampling 18 years of historical monthly California hydro generation data and estimating the associated monthly HLH and LLH electricity prices in the AURORA Model. *See* Chapter 4 of the Study, regarding the AURORA Model. The historical monthly California hydro generation data used to incorporate risk were collected from reports published by the Energy Information Administration (EIA) for 1980-1997. These data are reported in Table 6.5.

6.7.2 Sampling Hydro Generation. California hydro generation risk is modeled in RiskMod by randomly sampling, in the @RISK computer software, values from 1 to 18 (which represent each of the 18 hydro generation years) and using the associated hydro generation data in a continuous manner like that used for the 50 water year analysis. The random selection of the initial hydro generation year (for FY 2003) is accomplished by sampling real values ranging from 1 to 18 from a uniform probability distribution in a risk simulation model and subsequently converting each number to the nearest integer value (whole numbers). Given the sampled hydro generation year, the corresponding monthly California hydro generation data for that year are selected for FY 2003.

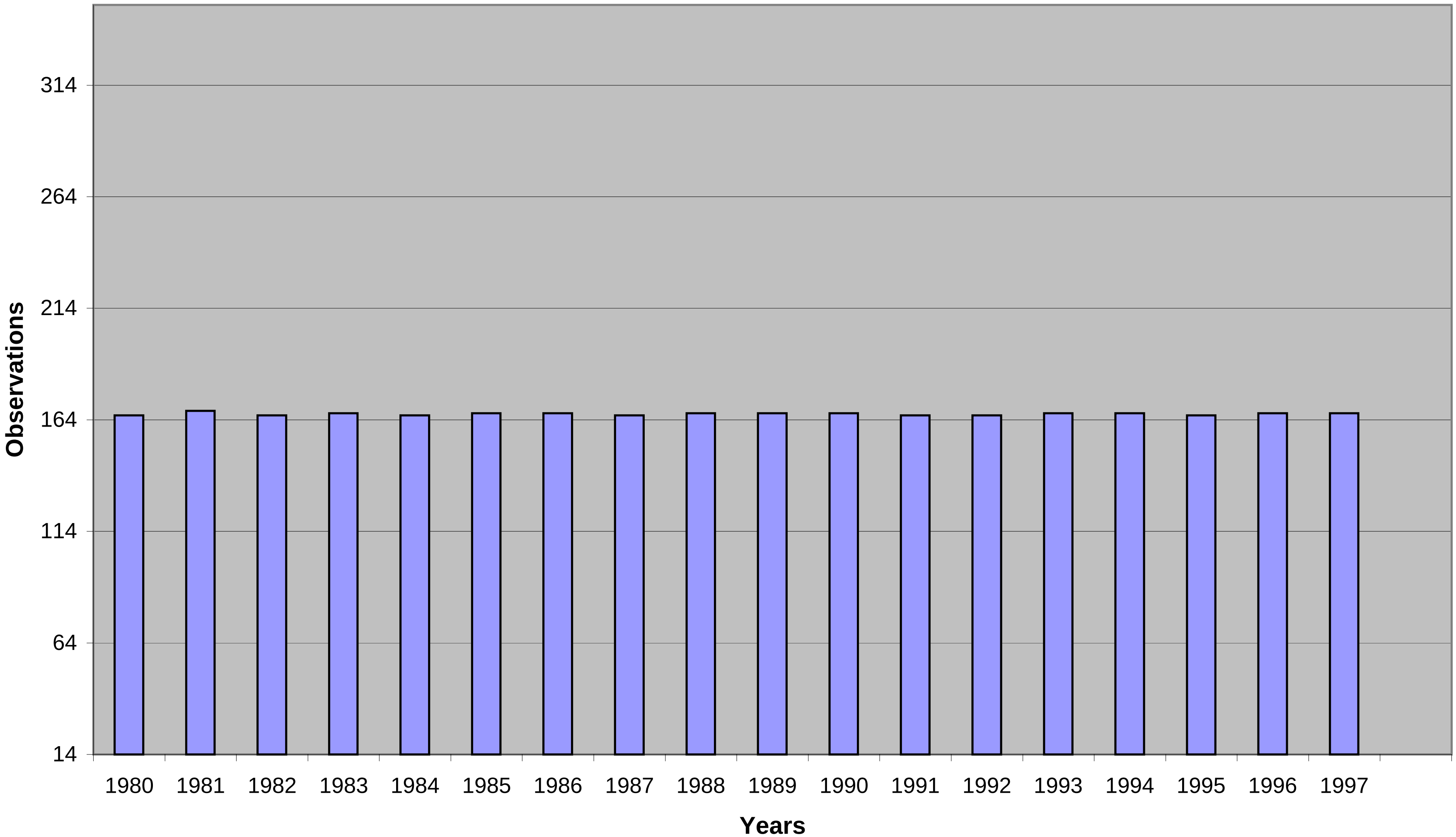
Graph 6.5 reports the number of times that each of the 18 years of hydro generation data were sampled from a uniform probability distribution for 3000 simulations. The uniform probability distribution was selected for use in the risk simulation model because it appropriately assigns

Table 6.5: California Hydro Generation for 1980 - 1997

	FY	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
1	1980	2983	2486	3179	5011	5351	6007	5438	5128	4957	5087	4858	4418
2	1981	3210	3132	3142	2450	2701	2894	3471	3633	3931	4043	3667	3243
3	1982	2179	3167	5336	5649	5884	6243	6757	6800	6332	5809	5587	5146
4	1983	4036	4933	5649	5778	6903	7276	7075	7563	7547	6945	6302	5601
5	1984	4668	5338	6956	6786	5430	5250	5222	5110	5375	5517	5235	4501
6	1985	3261	3315	3950	3195	3594	3522	4176	4366	3943	4501	3962	3476
7	1986	3114	3276	3062	3215	4975	6784	5851	5423	5701	5621	4812	4721
8	1987	3750	3274	2710	2011	2342	2446	3118	3230	3322	3923	3548	3081
9	1988	2422	1951	2214	2327	2115	2392	2764	2792	3524	4238	3687	2779
10	1989	1677	1858	1887	1421	2060	3349	4318	4313	4557	5048	4415	3149
11	1990	2605	2665	2454	1995	1671	2656	3128	3164	3428	4081	3712	2692
12	1991	2522	1828	1626	1267	1146	1626	1978	2293	3711	3992	3398	2879
13	1992	2157	1664	1776	1478	1767	1991	2369	3071	2978	3106	2559	2078
14	1993	1687	1424	1704	2403	3463	5177	5785	6293	6650	5819	5071	3604
15	1994	2878	2515	2703	1767	1708	2409	2713	3226	3860	3989	3599	2403
16	1995	1875	1465	2203	3738	5443	6431	7339	7484	7507	6694	6121	4915
17	1996	3853	2910	2591	3013	5684	6597	6871	6954	6089	5442	4883	3688
18	1997	3003	2926	5204	5597	5923	5171	4896	5321	5489	5245	4796	3838

Source: Energy Information Administration (EIA) - Electric Power Monthly, Table 11. Electric Utility Hydroelectric Net Generation by Census Division and State, 1980 - 1997

Graph 6.5: Number of Times California Hydro Generation for 18 Years were Sampled Based on 3000 Sampled Values



equal probability to each of the 18 years of data being sampled. The average number of times that each hydro generation year could have been sampled for 3000 simulations is 166.7 (3000/18). These results in Graph 6.5 indicate that all years, except for 1981, were sampled either 166 or 167 times. The hydro generation data for 1981 were sampled 168 times.

After the initial year is selected for FY 2003 for a given simulation, hydro generation data for a sequential set of four years of data, starting with the hydro generation year selected for FY 2003, are selected from 1 through 18. When the end of the data is reached (at the end of 18), monthly hydro generation data for hydro generation year 1 is subsequently used. Thus, if a simulation starts with hydro generation data for hydro generation year 17, the simulation will use hydro generation data for years 17 and 18, as well as years 1 and 2, for a total of four sequential years of hydro generation data. This approach was used so that each of the 18 years of California hydro generation data were sampled an equal number of times. Using historical California hydro generation data in this continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 18 years of hydro generation data.

6.7.3 Use of California Hydro Generation Risk in AURORA. Variability in California hydro generation is incorporated into the AURORA Model by calculating (via the Data Manager), from monthly California hydro generation data for 18 years, California annual energy-to-capacity ratios (using the total hydro capacity value for all of California in the AURORA Model), and calculating California monthly to annual hydro generation ratios. These data are input into the AURORA Model. *See* Chapter 4 of the Study, regarding the AURORA Model. These sets of ratios are used by AURORA to calculate the annual and then the monthly hydro generation for each of the two California regions (northern and southern California) in AURORA. This process results in the sum of the hydro generation for the two California regions in AURORA being equal to the historical monthly California hydro generation.

6.8 California Loads Risk Factor

California load uncertainty is incorporated into the Risk Analysis to account for the impact that California load uncertainty has on monthly HLH and LLH electricity prices, which impacts BPA's surplus energy revenues and power purchase expenses. This impact is accounted for by inputting into the AURORA Model various California load values and having it estimate the associated HLH and LLH electricity prices. *See* Chapter 4 of the Study, regarding the AURORA Model.

The California Load Risk Model is designed to incorporate forecasted monthly load data from the AURORA Model such that, when no risk is being simulated, the forecasted monthly loads match the sum of the forecasted loads for the two regions (southern and northern California) that comprise California in the AURORA Model. This process results in the simulated loads reflecting variability in loads relative to the forecasted loads used in AURORA. *Id.*
California load variability is modeled in the California Load Risk Model such that annual load growth variability and monthly load swings due to weather conditions are both accounted for in one California load variability factor. This task is accomplished by first simulating annual load growth for years from 2003-2006 and then, subsequently, simulating the impact of monthly load swings due to weather on the simulated monthly loads that include load growth.

6.8.1 Annual California Load Growth Risk. Annual California load growth risk is modeled using a random-walk technique. This quantitative method simulates various annual average load levels through time with the starting point for simulating the annual average load in a given year being the annual average load level from the previous year. Under this method, simulated annual average loads randomly increase and decrease through time from the annual average load level of the prior year with the results including outcomes that represent periods of strong load growth, weak load growth, and vacillating positive and negative load growth.

Input data from the AURORA Model used in the California Load Risk Model are the following: (1) annual average 2002 California loads; (2) forecasted annual load growth for 2003–2006; and (3) monthly load shaping factors (values relative to 1.00) that were derived for use in AURORA by dividing historical monthly loads by historical annual average loads. *See* Chapter 4 of the Study, regarding the AURORA Model. Inputting the data used by the AURORA Model allows the California Load Risk Model to replicate the forecasted monthly California loads in AURORA.

Load growth variability is incorporated into the California Load Risk Model by sampling values from standard normal distributions (normal distributions with a mean of 0 and a standard deviation of 1) in @RISK, multiplying the sampled values by an annual load growth standard deviation, and adding the simulated positive and negative values to the annual load level of the prior year. The values sampled from the standard normal distribution are in terms of the number of positive or negative standard deviations and they are identical to the values sampled from the standard normal distributions used to estimate load growth risk for the PNW. By using this approach, positive/negative load growth due to the economy in California is directly linked with positive/negative load growth in the PNW due to the economy. Variability in monthly loads due to load growth variability is derived by multiplying variable annual loads by deterministic monthly load shape factors. The annual load growth standard deviation used in the California Load Risk Model is 2.4 percent, which was derived from WECC load data from 1987-1998 for the California/Mexico Power Area. The source of this data was a publication by the WECC titled, 10-Year Coordinated Plan Summary 1999-2008, Planning and Operation for Electric System Reliability, Western Systems Coordinating Council, October 1999, at 60. The historical WECC load data and the annual load growth standard deviation calculations by BPA are reported in Tables 6.1 and 6.2.

6.8.2 California Load Risk Due to Weather Conditions. Monthly California load variability due to weather conditions is quantified by first sampling values from standard normal distributions in @RISK, then multiplying the sampled values by monthly load standard deviations, and finally adding the resulting positive and negative values to the simulated loads after load growth.

The monthly California load standard deviations are derived from utility-specific, monthly historical daily load standard deviations and 2005 forecasted loads for California utilities used as input data in PMDAM when performing the MCA in the 1996 rate case (*see* MCA Study Documentation, WP-96-FS-BPA-04A, Part 2 of 2; pages 305 and 256). This derivation is accomplished by calculating composite, load-weighted, monthly load standard deviations from utility specific, daily load standard deviations (for the 12 months of the year) and annual average load data.

6.8.3 Derivation of California Monthly Load Variability Due to Weather Conditions. BPA assumes, for Rate setting purposes, that daily weather patterns over the course of a month are independent and that each day of a given month has the same daily load standard deviation. Accordingly, BPA used the following statistical equation to derive monthly load standard deviations from daily load standard deviations for each month. The statistical equation for calculating the standard deviation for the average of "n" number of independent random variables is the following:

$$\sigma_{\bar{x}} = \frac{\sigma_x}{\sqrt{n}}$$

Where:

$\underline{\sigma_x}$ is the standard deviation for all independent random variables

$\overline{n}$ is the number of independent random variables

In the case of BPA's analysis, the number of independent random variables is the number of days in a month and the standard deviation for all the independent random variables is the daily load standard deviations for each month. The California monthly load standard deviations for each month are derived by inserting values for the number of days in each month and the daily load standard deviations for each month into the equation above.

Daily California load standard deviations for each month and the resulting California monthly load standard deviations are reported in Table 6.6. These monthly load standard deviations are input into the California Load Risk Model to quantify monthly load variability due to weather in RiskSim. Table 6.7 contains a copy of the California Load Risk Model**.** Results from this risk model are shown in Graph 6.6 for the 5^{th}, 50^{th}, and 95^{th} percentiles.

6.8.4 Use of Simulated California Loads in AURORA. The HLH and LLH electricity prices associated with changes in California monthly loads are estimated in the AURORA Model by inputting California load data simulated by the California Load Risk Model. *See* Chapter 4 of the Study, regarding the AURORA Model. This process involves calculating (via the Data Manager) monthly load ratios (monthly loads divided by the annual average loads) from monthly and annual load data simulated by the California Load Risk Model and then inputting the monthly ratios and annual average energy loads into the AURORA Model for each simulation. These data are input into AURORA to calculate annual and monthly loads for each of the two California regions (southern and northern California) in AURORA. This process results in the sum of the loads for the two California regions in AURORA being equal to the simulated California loads from the California Load Risk Model.

Table 6.6: Derivation of Load-Weighted, Monthly Load Standard Deviations for California

California

		Loads CY 2005	Daily Load Standard Deviations											
			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SCE	SCEFRM	11497	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.09	0.11	0.09	0.09	0.09
SCE	AAAFRM	423	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.09	0.11	0.09	0.09	0.09
SCE	BCRVFM	420	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.09	0.11	0.09	0.09	0.09
SCE	DWRFRM	910	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.09	0.11	0.09	0.09	0.09
LADWP	LADFRM	3366	0.09	0.09	0.10	0.10	0.10	0.11	0.12	0.11	0.12	0.11	0.10	0.09
SDG&E	SDEFRM	2319	0.07	0.08	0.07	0.07	0.08	0.09	0.09	0.09	0.10	0.08	0.07	0.07
OSC	BGPFRM	442	0.09	0.08	0.09	0.09	0.10	0.10	0.11	0.10	0.11	0.10	0.09	0.09
OSC	IIDOFM	474	0.09	0.08	0.09	0.09	0.10	0.10	0.11	0.10	0.11	0.10	0.09	0.09
PG&E	PG&FRM	10987	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	NCPFRM	393	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	REDFRM	130	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	SNCFRM	305	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	MIDFRM	275	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	TIDFRM	200	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	SMUFRM	1271	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
Total Cal		**33412**												

		Loads CY 2005	Daily Load Variances											
			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SCE	SCEFRM	11497	0.0081	0.0081	0.0081	0.0081	0.0100	0.0100	0.0100	0.0081	0.0121	0.0081	0.0081	0.0081
SCE	AAAFRM	423	0.0081	0.0081	0.0081	0.0081	0.0100	0.0100	0.0100	0.0081	0.0121	0.0081	0.0081	0.0081
SCE	BCRVFM	420	0.0081	0.0081	0.0081	0.0081	0.0100	0.0100	0.0100	0.0081	0.0121	0.0081	0.0081	0.0081
SCE	DWRFRM	910	0.0081	0.0081	0.0081	0.0081	0.0100	0.0100	0.0100	0.0081	0.0121	0.0081	0.0081	0.0081
LADWP	LADFRM	3366	0.0081	0.0081	0.0100	0.0100	0.0100	0.0121	0.0144	0.0121	0.0144	0.0121	0.0100	0.0081
SDG&E	SDEFRM	2319	0.0049	0.0064	0.0049	0.0049	0.0064	0.0081	0.0081	0.0081	0.0100	0.0064	0.0049	0.0049
OSC	BGPFRM	442	0.0081	0.0064	0.0081	0.0081	0.0100	0.0100	0.0121	0.0100	0.0121	0.0100	0.0081	0.0081
OSC	IIDOFM	474	0.0081	0.0064	0.0081	0.0081	0.0100	0.0100	0.0121	0.0100	0.0121	0.0100	0.0081	0.0081
PG&E	PG&FRM	10987	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	NCPFRM	393	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	REDFRM	130	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	SNCFRM	305	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	MIDFRM	275	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	TIDFRM	200	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	SMUFRM	1271	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
Total Cal		**33412**												
Number of Days Per Month			31	28	31	30	31	30	31	31	30	31	30	31
Weighted Daily Load Variances			**0.0066**	**0.0066**	**0.0068**	**0.0068**	**0.0090**	**0.0093**	**0.0096**	**0.0079**	**0.0106**	**0.0071**	**0.0068**	**0.0066**
Weighted Daily Load Standard Deviations			**0.0811**	**0.0815**	**0.0823**	**0.0823**	**0.0948**	**0.0965**	**0.0980**	**0.0887**	**0.1028**	**0.0845**	**0.0823**	**0.0811**
Monthly Load Standard Deviations			**0.0146**	**0.0154**	**0.0148**	**0.0150**	**0.0170**	**0.0176**	**0.0176**	**0.0159**	**0.0188**	**0.0152**	**0.0150**	**0.0146**

Table 6.7: California Load Risk Model for 2003 - 2006

California Load Variability

California Load Growth Uncertainty:

Forecasted Calendar Year (2002) Annual Average California Loads	31,960
Forecasted California Load Growth for 2002; Source: Aurora	0.00%
Forecasted California Load Growth for 2003; Source: Aurora	1.96%
Forecasted California Load Growth for 2004; Source: Aurora	2.68%
Forecasted California Load Growth for 2005; Source: Aurora	2.72%
Forecasted California Load Growth for 2006; Source: Aurora	2.70%
Load Growth Std Dev; Source: PMDAM	2.40%

Estimated Base Case Loads		*Std Normal Dist - Using the Same as PNW*
CY 2002	31,960	*0.0*
CY 2003	32,587	*0.0*
CY 2004	33,460	*0.0*
CY 2005	34,371	*0.0*
CY 2006	35,299	*0.0*

Load Growth Dev from any specified forecasted load level	
CY 2002	*31960*
CY 2003	*32587*
CY 2004	*33460*
CY 2005	*34371*
CY 2006	*35299*

California Load Variability Due to Load Growth Uncertainty

Calendar Year 2003

	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	Jul '03	Aug '03	Sep '03	Oct '03	Nov '03	Dec '03	Average
Average Annual California Loads (Average Energy in aMW)	32587	32587	32587	32587	32587	32587	32587	32587	32587	32587	32587	32587	
California Monthly Load Shapes (Source: AURORA)	0.953	0.933	0.919	0.925	0.955	1.063	1.125	1.167	1.075	0.971	0.943	0.961	
Simulated Monthly California Loads (Average Energy in aMW)	31067	30416	29960	30155	31132	34649	36669	38035	35038	31653	30741	31328	32,570 aMW

California Load Variability Due to Load Growth and Weather Uncertainty

	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	Jul '03	Aug '03	Sep '03	Oct '03	Nov '03	Dec '03	
California Loads (Average Energy in aMW); (From California Load Growth Worksheet)	31067	30416	29960	30155	31132	34649	36669	38035	35038	31653	30741	31328	32,570 aMW
Monthly Load Standard Deviation (Derived, Via Simulation, from Daily Load Standard Deviations in PMDAM)	1.46%	1.54%	1.48%	1.50%	1.70%	1.76%	1.76%	1.59%	1.88%	1.52%	1.50%	1.46%	
Random California Non-Fed Loads (Average Energy in aMW)	*31,067*	*30,416*	*29,960*	*30,155*	*31,132*	*34,649*	*36,669*	*38,035*	*35,038*	*31,653*	*30,741*	*31,328*	32,570 aMW

Table 6.7: California Load Risk Model for 2004 (Continued)

California Load Variability

California Load Variability Due to Load Growth Uncertainty

	Calendar Year 2004												
	Jan '04	**Feb '04**	**Mar '04**	**Apr '04**	**May '04**	**Jun '04**	**Jul '04**	**Aug '04**	**Sep '04**	**Oct '04**	**Nov '04**	**Dec '04**	**Average**
Average Annual California Loads (Average Energy in aMW)	33460	33460	33460	33460	33460	33460	33460	33460	33460	33460	33460	33460	
California Monthly Load Shapes (Source: AURORA)	**0.953**	**0.933**	**0.919**	**0.925**	**0.955**	**1.063**	**1.125**	**1.167**	**1.075**	**0.971**	**0.943**	**0.961**	
Simulated Monthly California Loads (Average Energy in aMW)	31900	31231	30763	30963	31966	35578	37652	39054	35977	32501	31565	32168	**33,443 aMW**

California Load Variability Due to Load Growth and Weather Uncertainty

	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	Jul '04	Aug '04	Sep '04	Oct '04	Nov '04	Dec '04	
California Loads (Average Energy in aMW); (From California Load Growth Worksheet)	31900	31231	30763	30963	31966	35578	37652	39054	35977	32501	31565	32168	**33,443 aMW**
Monthly Load Standard Deviation (Derived, Via Simulation, from Daily Load Standard Deviations in PMDAM)	1.46%	1.54%	1.48%	1.50%	1.70%	1.76%	1.76%	1.59%	1.88%	1.52%	1.50%	1.46%	
Random California Non-Fed Loads (Average Energy in aMW)	***31,900***	***31,231***	***30,763***	***30,963***	***31,966***	***35,578***	***37,652***	***39,054***	***35,977***	***32,501***	***31,565***	***32,168***	**33,443 aMW**

Table 6.7: California Load Risk Model for 2005 (Continued)

California Load Variability

California Load Variability Due to Load Growth Uncertainty

Calendar Year 2005

	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	Jul '05	Aug '05	Sep '05	Oct '05	Nov '05	Dec '05	Average
Average Annual California Loads (Average Energy in aMW)	34371	34371	34371	34371	34371	34371	34371	34371	34371	34371	34371	34371	
California Monthly Load Shapes (Source: AURORA)	**0.953**	**0.933**	**0.919**	**0.925**	**0.955**	**1.063**	**1.125**	**1.167**	**1.075**	**0.971**	**0.943**	**0.961**	
Simulated Monthly California Loads (Average Energy in aMW)	32767	32080	31599	31805	32836	36545	38676	40117	36956	33385	32424	33043	**34,353 aMW**

California Load Variability Due to Load Growth and Weather Uncertainty

	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	Jul '05	Aug '05	Sep '05	Oct '05	Nov '05	Dec '05	
California Loads (Average Energy in aMW); (From California Load Growth Worksheet)	32767	32080	31599	31805	32836	36545	38676	40117	36956	33385	32424	33043	**34,353 aMW**
Monthly Load Standard Deviation (Derived, Via Simulation, from Daily Load Standard Deviations in PMDAM)	1.46%	1.54%	1.48%	1.50%	1.70%	1.76%	1.76%	1.59%	1.88%	1.52%	1.50%	1.46%	
Random California Non-Fed Loads (Average Energy in aMW)	***32,767***	***32,080***	***31,599***	***31,805***	***32,836***	***36,545***	***38,676***	***40,117***	***36,956***	***33,385***	***32,424***	***33,043***	**34,353 aMW**

Table 6.7: California Load Risk Model for 2006 (Continued)

California Load Variability

California Load Variability Due to Load Growth Uncertainty

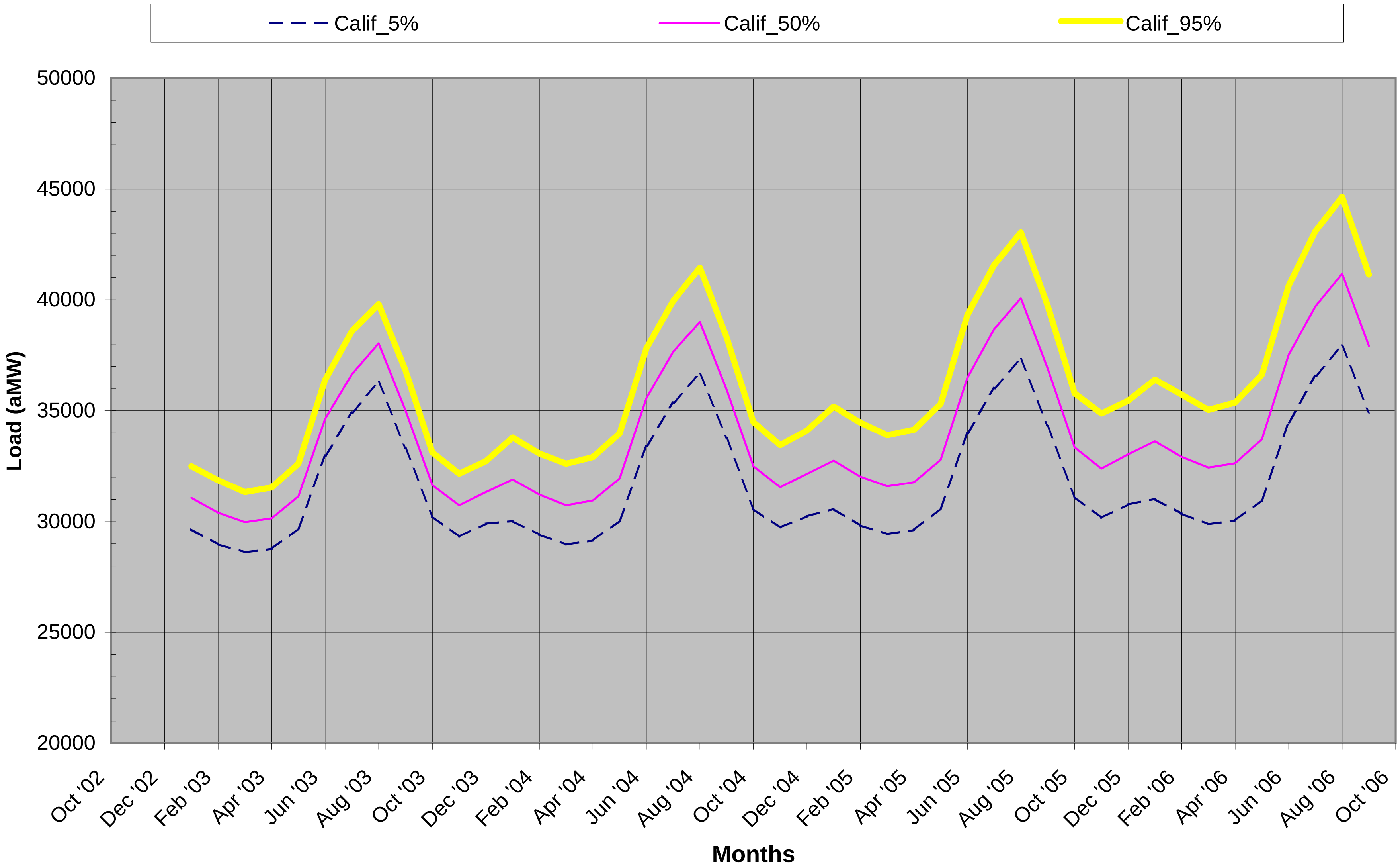
Calendar Year 2006

	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	Average
Average Annual California Loads (Average Energy in aMW)	35299	35299	35299	35299	35299	35299	35299	35299	35299	35299	35299	35299	
California Monthly Load Shapes (Source: AURORA)	**0.953**	**0.933**	**0.919**	**0.925**	**0.955**	**1.063**	**1.125**	**1.167**	**1.075**	**0.971**	**0.943**	**0.961**	
Simulated Monthly California Loads (Average Energy in aMW)	33652	32947	32452	32664	33722	37532	39720	41200	37954	34286	33299	33935	**35,280 aMW**

California Load Variability Due to Load Growth and Weather Uncertainty

	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	
California Loads (Average Energy in aMW); (From California Load Growth Worksheet)	33652	32947	32452	32664	33722	37532	39720	41200	37954	34286	33299	33935	**35,280 aMW**
Monthly Load Standard Deviation (Derived, Via Simulation, from Daily Load Standard Deviations in PMDAM)	1.46%	1.54%	1.48%	1.50%	1.70%	1.76%	1.76%	1.59%	1.88%	1.52%	1.50%	1.46%	
Random California Non-Fed Loads (Average Energy in aMW)	***33,652***	***32,947***	***32,452***	***32,664***	***33,722***	***37,532***	***39,720***	***41,200***	***37,954***	***34,286***	***33,299***	***33,935***	**35,280 aMW**

Graph 6.6: Simulated California Loads for 2003 - 2006



6.9 Natural Gas Price Risk Factor

Variability in natural gas prices is incorporated into the Risk Analysis to account for the impact that natural gas price risk has on monthly HLH and LLH electricity prices--which impacts BPA's surplus energy revenues and power purchase expenses. This impact is accounted for by inputting into the AURORA Model the simulated real monthly natural gas prices from the Natural Gas Price Risk Model and having AURORA estimate the associated nominal monthly HLH and LLH electricity prices for each simulation. *See* Chapter 4 of the Study, regarding the AURORA Model.

The Natural Gas Price Risk Model is designed to simulate various gas price patterns through time. The modeling method used to simulate gas price patterns through time is a mean-reverting, random-walk technique. The random-walk technique simulates monthly natural gas prices through time with the starting point for simulating the natural gas price in a given month being the monthly natural gas price from the prior month. Under this method, simulated monthly natural gas prices randomly increase and decrease through time from the natural gas price of the prior month. The mean-reverting technique increases the likelihood that simulated natural gas price movements over time will tend to move toward (rather than randomly away from) the mean (or forecasted) prices, with this tendency to move toward the mean prices increasing the greater the difference between the simulated and the forecasted prices.

6.9.1 Inputs into the Natural Gas Price Risk Model. The Natural Gas Price Risk Model is designed to simulate variable natural gas prices based on the natural gas price forecast used in the AURORA Model. *See* Chapter 4 of the Study, regarding the AURORA Model. To accomplish this task, forecasted average annual delivered natural gas prices (in real $) to southern California for 2003-2006 and monthly gas price shape data (values relative to 1.00) from AURORA are input into the Natural Gas Price Risk Model. *Id.* With this data, the deterministic forecasted monthly prices in AURORA are calculated in the Natural Gas Price Risk Model by multiplying the annual average natural gas prices by the monthly gas price shapes.

Additional information input into the Natural Gas Price Risk Model are minimum and maximum delivered gas price constraints (in real $) and monthly standard deviations for natural gas prices calculated from historical monthly spot market gas prices in terms of price movements from one month to the next month. Minimum and maximum delivered gas price constraints used in the Natural Gas Risk Model are $1.50/MMBTU (Million British Thermal Units) and $20.00/MMBTU. These price constraints are determined based on BPA's professional judgment.

Historical monthly spot market gas prices used to calculate the standard deviations for month-to-month price movements are for Ignacio, Colorado from January 1989 through December 2002. Monthly price variability is estimated in terms of month-to-month price changes so that price movements through time could be modeled using the random-walk technique. The month-to-month price changes were measured in terms of taking the natural logarithm of the ratio between each monthly price and the prior monthly price. The monthly price variability was computed by taking the standard deviation of these natural logarithm values. This approach allowed natural gas price risk to be reflected in a normal probability distribution of natural log values, and once these natural log values were sampled, they were then converted into a lognormal probability distribution of normal (non-logged) values by taking the antilog of the natural log values.

6.9.2 Modeling Natural Gas Price Variability. Statistical parameters needed to quantify risk in probability distributions in the Natural Gas Price Risk Model are developed from the Ignacio price data. This quantification allows the variability in the historical natural gas price data for Ignacio to be incorporated into the Natural Gas Price Risk Model. This process is performed in the following manner: (1) the changes in gas prices from one month to the next month for all months from January 1989 through December 2002 are calculated by dividing each monthly price by the prior monthly price and taking the natural logarithm; (2) the lognormal price changes according to month are accumulated; and (3) the standard deviation for all lognormal price changes for each month are calculated. This process results in standard deviations being calculated from 14 price deltas for all months of the year except for January (which is derived from a set of 13 price deltas). Table 6.8 contains the historical Ignacio monthly spot market natural gas prices and the calculations used to derive these statistical parameters.

The monthly standard deviations and the largest allowable monthly standard deviation values were input into truncated standard normal probability distributions in @RISK. A truncated standard normal distribution is a normal distribution having a mean of zero, a standard deviation of one, and a specified maximum and minimum value that sets an upper and lower bound on the values that can be sampled. In the @RISK computer software, this information is entered into a truncated normal probability distribution as follows:

RiskTNormal(Mean = 0, Standard deviation = 1, Min value = , Max value =).
(Where RiskTNormal = truncated normal probability distribution in @RISK)

Under this methodology, the positive and negative values sampled from the truncated standard normal distributions are the number of standard deviations of a random price movement. The number of standard deviations sampled from the monthly truncated standard normal distributions in the Natural Gas Price Risk Model are multiplied by the monthly standard deviations and the antilog of these natural logarithm price changes are multiplied times the simulated natural gas price for the prior month to derive each subsequent monthly price.

Table 6.8: Statistical Parameter Calculations for Natural Gas Price Risk Model

Ignacio Monthly Spot Gas Prices ($/MMBTU)

	1	2	3	4	5	6	7	8	9	10	11	12	Annual
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Average**
1989	2.22	2.13	2.03	2.16	2.16	2.09	2.11	2.09	2.00	1.97	2.13	2.86	**2.16**
1990	3.27	2.27	1.80	1.81	1.78	1.82	1.78	1.75	1.73	2.13	2.42	2.30	**2.07**
1991	1.97	1.42	1.24	1.29	1.25	1.22	1.24	1.32	1.50	1.52	2.01	2.01	**1.50**
1992	1.47	1.33	1.41	1.60	1.69	1.76	1.85	2.11	2.50	2.45	2.41	2.47	**1.92**
1993	2.30	1.97	2.39	2.25	2.10	1.95	2.06	2.21	2.32	2.12	2.22	2.30	**2.18**
1994	2.07	2.38	2.14	1.96	1.84	1.70	1.77	1.76	1.48	1.45	1.66	1.77	**1.83**
1995	1.41	1.22	1.21	1.25	1.27	1.26	1.11	1.33	1.39	1.30	1.35	1.38	**1.29**
1996	1.30	1.31	1.26	1.24	1.21	1.40	1.86	2.01	1.66	1.96	2.82	3.72	**1.81**
1997	3.73	2.56	1.69	1.81	2.00	2.07	2.14	2.37	2.75	2.90	3.09	2.26	**2.45**
1998	2.08	2.02	2.16	2.27	2.02	1.76	1.97	1.85	1.78	1.78	2.00	1.83	**1.96**
1999	1.82	1.69	1.56	1.83	2.07	2.09	2.08	2.46	2.45	2.59	2.32	2.29	**2.10**
2000	2.26	2.43	2.61	2.77	3.07	4.36	3.74	3.45	4.16	4.55	5.16	7.72	**3.86**
2001	8.08	5.62	4.76	4.55	3.49	2.64	2.41	2.52	1.81	2.07	2.16	2.23	**3.53**
2002	2.02	2.04	2.59	2.53	2.40	2.23	2.45	2.34	2.31	2.66	3.24	3.71	**2.54**
Min	1.30	1.22	1.21	1.24	1.21	1.22	1.11	1.32	1.39	1.30	1.35	1.38	1.29
Avg	**2.57**	**2.17**	**2.06**	**2.09**	**2.03**	**2.02**	**2.04**	**2.11**	**2.14**	**2.23**	**2.47**	**2.74**	**2.10**
Max	8.08	5.62	4.76	4.55	3.49	4.36	3.74	3.45	4.16	4.55	5.16	7.72	3.86
Stdev	**1.72**	**1.09**	**0.92**	**0.85**	**0.65**	**0.77**	**0.62**	**0.54**	**0.78**	**0.87**	**0.97**	**1.67**	**0.636**

Ignacio Month-to-Month Spot Gas Price Deltas ($/MMBTU)

1989		-0.05	-0.05	0.07	0.00	-0.03	0.01	-0.01	-0.04	-0.02	0.08	0.29
1990	0.14	-0.37	-0.23	0.00	-0.02	0.02	-0.02	-0.02	-0.01	0.21	0.13	-0.05
1991	-0.16	-0.33	-0.13	0.04	-0.03	-0.02	0.02	0.06	0.12	0.01	0.28	0.00
1992	-0.31	-0.10	0.06	0.13	0.05	0.04	0.05	0.13	0.17	-0.02	-0.02	0.02
1993	-0.07	-0.15	0.19	-0.06	-0.07	-0.08	0.05	0.07	0.05	-0.09	0.05	0.03
1994	-0.10	0.14	-0.11	-0.09	-0.06	-0.08	0.04	-0.01	-0.17	-0.02	0.13	0.06
1995	-0.22	-0.14	-0.01	0.03	0.02	-0.01	-0.12	0.18	0.05	-0.07	0.04	0.02
1996	-0.07	0.01	-0.04	-0.02	-0.02	0.15	0.28	0.08	-0.19	0.16	0.36	0.28
1997	0.00	-0.38	-0.42	0.07	0.10	0.03	0.03	0.10	0.15	0.05	0.07	-0.31
1998	-0.08	-0.03	0.07	0.05	-0.11	-0.14	0.11	-0.06	-0.04	0.00	0.12	-0.09
1999	-0.01	-0.07	-0.08	0.16	0.12	0.01	-0.01	0.16	0.00	0.05	-0.11	-0.01
2000	-0.01	0.07	0.07	0.06	0.10	0.35	-0.15	-0.08	0.19	0.09	0.13	0.40
2001	0.05	-0.36	-0.17	-0.05	-0.27	-0.28	-0.09	0.04	-0.33	0.13	0.04	0.03
2002	-0.10	0.01	0.24	-0.02	-0.05	-0.07	0.09	-0.05	-0.01	0.14	0.20	0.14
Average	**-0.07**	**-0.12**	**-0.04**	**0.03**	**-0.02**	**-0.01**	**0.02**	**0.04**	**-0.01**	**0.05**	**0.11**	**0.06**

Table 6.8: (Continued)

Ignacio Month-to-Month Spot Gas Price Deltas from Average ($/MMBTU)

	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1989		0.08	0.00	0.04	0.01	-0.03	-0.01	-0.05	-0.04	-0.06	-0.03	0.23
	1990	0.21	-0.24	-0.19	-0.02	0.00	0.03	-0.05	-0.06	0.00	0.16	0.02	-0.11
	1991	-0.08	-0.20	-0.09	0.01	-0.01	-0.01	0.00	0.02	0.13	-0.03	0.17	-0.06
	1992	-0.24	0.02	0.10	0.10	0.07	0.05	0.03	0.09	0.17	-0.07	-0.12	-0.04
	1993	0.00	-0.03	0.24	-0.09	-0.05	-0.07	0.03	0.03	0.05	-0.14	-0.06	-0.03
	1994	-0.03	0.26	-0.06	-0.12	-0.04	-0.08	0.02	-0.05	-0.17	-0.06	0.03	0.00
	1995	-0.15	-0.02	0.03	0.01	0.03	0.00	-0.14	0.13	0.05	-0.11	-0.07	-0.04
	1996	0.01	0.14	0.00	-0.05	0.00	0.15	0.26	0.03	-0.18	0.12	0.26	0.22
	1997	0.07	-0.25	-0.37	0.04	0.12	0.04	0.01	0.06	0.16	0.01	-0.04	-0.37
	1998	-0.01	0.09	0.11	0.02	-0.10	-0.13	0.09	-0.10	-0.04	-0.05	0.01	-0.15
	1999	0.07	0.05	-0.04	0.14	0.14	0.02	-0.03	0.12	0.00	0.01	-0.22	-0.07
	2000	0.06	0.20	0.11	0.04	0.12	0.36	-0.17	-0.12	0.19	0.04	0.02	0.34
	2001	0.12	-0.24	-0.12	-0.07	-0.25	-0.27	-0.11	0.00	-0.33	0.09	-0.06	-0.03
	2002	-0.03	0.13	0.28	-0.05	-0.04	-0.07	0.07	-0.09	-0.01	0.10	0.09	0.08
Avg		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Stdev of Deltas		**0.115**	**0.172**	**0.170**	**0.071**	**0.100**	**0.142**	**0.107**	**0.083**	**0.148**	**0.090**	**0.118**	**0.178**

The mean-reversion methodology was modeled using an algorithm and a set of monthly mean reversion decay parameters (decay parameters) that adjust the value of the mean in each of the monthly truncated standard normal distributions from the typical constant of zero. The mean-reversion methodology was modeled as follows:

Simulated monthly price changes = RiskTNormal (Monthly mean-reversion decay parameters * (1 - Simulated mean-reversion ratios), 1 - Maximum monthly standard deviation, + Maximum monthly standard deviation) * monthly standard deviations

Where

RiskTNormal = Truncated normal probability distribution in @RISK with
Mean = Monthly mean-reversion decay parameters * (1- Simulated mean-reversion ratios)
Standard deviation = 1
Minimum value = - Maximum standard deviation
Maximum value = + Maximum standard deviation
And

Monthly mean-reversion decay parameters = Calibrated monthly price decay values
Simulated mean-reversion ratios = Simulated prior month price / Forecasted prior month price

6.9.3 Calibrating Natural Gas Price Variability. The final step in the modeling process is the derivation of monthly mean reversion decay parameters to better calibrate the natural gas price variability simulated by the Natural Gas Price Risk Model to the historical variability reflected in the Ignacio natural gas price data. This calibration process involves running the Natural Gas Price Risk Model and modifying the monthly decay parameters. The calibration of the decay values is performed in the following manner: (1) run the model; (2) calculate monthly and annual price standard deviations from the simulated data and compare the results to monthly and annual price standard deviations for the historical data; and (3) revise the decay values to test how well the monthly and annual variability of the simulated prices for a set of monthly decay values approximate the monthly and annual variability in the historical gas price data.

BPA used the statistical approach of minimizing the sum of residuals squared to help objectively determine the relative merits of one set of monthly decay values versus another. The sum of residuals squared is calculated by squaring the difference between each historical monthly natural gas price standard deviation and each simulated monthly natural gas price deviation and summing these squared differences. The lower the sum of residuals squared, the better the simulated monthly gas price variability approximates the historical monthly gas price variability. In addition to calculating the sum of residuals squared on monthly data, a set of decay values was also subjectively assessed to see how closely the annual variability of the simulated natural gas prices approximates the annual variability in the historical natural gas price data. Table 6.9 contains the results from the final calibration simulation.

The use of decay parameters, coupled with each month having different month-to-month gas price standard deviations, allows the Natural Gas Price Risk Model the flexibility to simulate that natural gas prices are more volatile in some months than others and that gas prices rise and fall at different rates during the year. Thus, the flexibility associated with the methodology utilized in the Natural Gas Price Risk Model allows the model to closely calibrate to the attributes of gas price movements in the historical data.

Table 6-10 contains a copy of the Natural Gas Price Risk Model. Results from this risk model are shown in Graph 6-7 for the 5^{th}, 50^{th}, and 95^{th} percentiles.

Table 6.9: Simulated Delivered Natural Gas Prices to Southern California for 2004 (Real$/MMBTU)

Simulation #	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg	
1	3.8822	4.6742	3.9766	3.3045	3.0467	3.1072	3.0128	2.8428	2.5919	2.9919	3.0465	3.1612	3.30	
2	3.1387	3.0166	3.5703	2.7518	2.8932	2.9263	3.0912	3.2212	3.6921	3.9655	3.5615	3.8623	3.31	
3	3.8550	4.0658	5.0661	4.4621	4.8081	4.5512	3.6416	3.9953	3.9497	3.5740	3.9154	4.2951	4.18	
4	3.6834	3.6070	2.9633	2.1530	2.3103	2.5737	2.6541	3.0956	2.9810	3.3493	3.6179	2.7998	2.98	
5	3.8453	3.9069	4.0955	3.4750	3.1348	3.4839	3.2489	3.3140	3.4843	3.7534	3.4375	3.2839	3.54	
6	4.8082	4.2134	4.1408	3.4197	3.0797	2.9473	3.1119	3.0566	2.9611	3.1711	3.1327	3.5432	3.47	
7	3.7201	3.8753	3.3375	3.5040	2.8268	2.7281	2.4364	2.3359	2.3938	2.8242	3.3275	2.9934	3.03	
8	3.1934	3.7723	3.7564	3.3197	3.4777	3.1649	3.2047	3.6748	3.6701	3.3744	3.6693	3.3489	3.47	
9	3.1807	3.1639	2.5381	2.3600	2.1951	2.0282	1.8274	2.0567	1.9264	1.8669	2.1580	2.0850	2.28	
10	5.6523	6.1827	4.2369	4.5274	4.1464	3.9994	3.9568	3.8410	3.7844	3.1564	2.7656	2.4763	4.06	
						.								
						.								
						.								
290	4.7359	3.7570	3.3959	2.9077	2.6284	2.6431	2.9911	2.8692	3.2827	2.9614	2.9082	2.4141	3.12	
291	1.7003	2.0747	1.8314	1.5000	1.5000	2.1331	2.0923	1.9560	2.3317	2.0767	2.1756	2.4333	1.98	
292	3.0116	2.4432	2.7264	2.3416	2.1052	1.8945	1.7867	1.9395	1.9634	2.1240	2.0237	2.1990	2.21	
293	3.8709	3.4749	3.5856	3.4938	3.2957	3.4085	3.3352	3.1643	3.4167	3.5975	3.9519	4.5242	3.59	
294	4.4471	4.0174	3.9177	4.0274	4.3579	3.9935	3.8754	3.6387	3.3336	3.1950	3.5516	3.9459	3.86	
295	2.5807	2.1795	2.2397	2.0848	2.3259	1.7887	1.9398	2.0310	2.0038	2.1961	2.0642	1.6309	2.09	
296	4.2459	3.3059	4.2545	4.2460	3.8196	2.8811	3.2675	3.4598	4.1144	4.1768	4.4735	4.0846	3.86	
297	3.9716	3.1233	2.0364	1.7775	1.6980	1.8933	2.3650	2.1955	1.7845	1.5679	1.9126	1.8220	2.18	
298	3.1529	3.7662	5.6625	4.2642	3.3679	2.5827	1.8725	1.9528	1.7598	1.7008	1.8200	1.8923	2.82	
299	3.1880	2.6717	2.2434	2.0232	2.2027	2.2038	2.0413	2.2669	2.1675	2.1465	2.3780	2.6690	2.35	
300	3.9186	3.7749	3.4320	3.1693	3.2028	3.1095	2.7758	3.0657	2.6202	2.6816	3.5015	3.3087	3.21	
Avg	**3.67**	**3.59**	**3.44**	**3.01**	**2.90**	**2.88**	**2.88**	**2.87**	**2.87**	**2.87**	**2.97**	**3.10**	**3.09**	**SIM**
Max	**7.07**	**7.13**	**6.70**	**5.90**	**5.45**	**5.66**	**6.39**	**5.32**	**5.48**	**5.20**	**4.99**	**5.71**	**4.83**	**SIM**
Min	**1.50**	**1.50**	**1.50**	**1.50**	**1.50**	**1.50**	**1.50**	**1.50**	**1.50**	**1.50**	**1.50**	**1.50**	**1.67**	**SIM**

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Mean Reversion Rate	**1.00**	**1.00**	**1.50**	**1.50**	**1.75**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	
Simulation Stdev	**0.994**	**1.000**	**0.967**	**0.872**	**0.772**	**0.754**	**0.753**	**0.723**	**0.721**	**0.718**	**0.726**	**0.811**	**0.637**
Historical Data Stdev	**1.718**	**1.088**	**0.916**	**0.847**	**0.647**	**0.774**	**0.616**	**0.540**	**0.779**	**0.871**	**0.967**	**1.674**	**0.636**
Sim Less Hist Stdev	**-0.724**	**-0.088**	**0.051**	**0.025**	**0.125**	**-0.020**	**0.137**	**0.183**	**-0.058**	**-0.154**	**-0.241**	**-0.863**	**0.001**
Residual ^2	**0.5246**	**0.0078**	**0.0026**	**0.0006**	**0.0157**	**0.0004**	**0.0188**	**0.0336**	**0.0034**	**0.0236**	**0.0579**	**0.7443**	**0.0000**
Sum of Squares	**1433.38**												**0.002**

Table 6.10: Natural Gas Price Risk Model

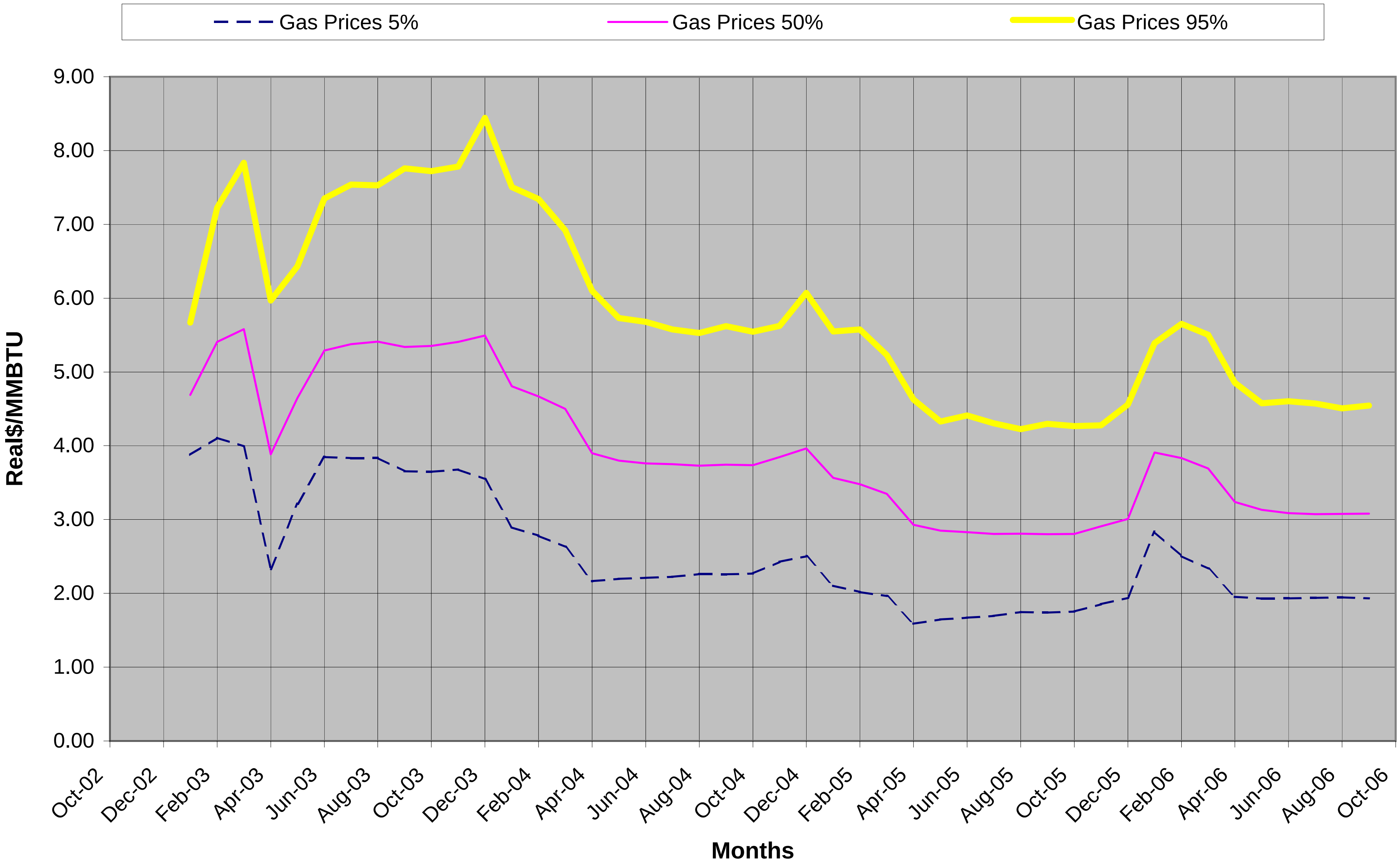
S. California Real Delivered Prices from AURORA	Base Case	Minimum	Maximum	Sim Unconstrained	Sim Constrained
CY 2003 Avg	5.20	1.50	20.00	5.20	5.20
CY 2004 Avg	4.12	1.50	20.00	4.12	4.12
CY 2005 Avg	3.12	1.50	20.00	3.12	3.12
CY 2006 Avg	3.37	1.50	20.00	3.37	3.37
CY02-06 Avg	3.95	1.50	20.00	3.95	3.95

	Expected Price ($/MMBTU)	Standard Normal Truncated Distribution N(var mean, 1); Includes Max and Min Std Devs	Monthly Volatility	Price Risk ($/MMBTU)	Standard Normal Distribution Mean Adjustor (Causes Mean Reversion)	Monthly Log Standard Deviation	Mean Reversion Decay Parameters (Use Values >=1)	Maximum and Minimum Standard Deviations	Monthly Gas Price Shapes	Expected Price ($/MMBTU)	Minimum Price ($/MMBTU)	Maximum Price ($/MMBTU)	Unconstrained Simulated Prices ($/MMBTU)	Constrained Simulated Prices ($/MMBTU)
Initial Value					*1.00*									
Jan-03	4.69	0.00	0.12	4.69	1.00	0.115	1.00	4.00	0.90	4.69	1.50	20.00	4.69	4.69
Feb-03	5.40	0.00	0.17	5.40	1.00	0.172	1.00	4.00	1.04	5.40	1.50	20.00	5.40	5.40
Mar-03	5.59	0.00	0.17	5.59	1.00	0.170	1.50	4.00	1.08	5.59	1.50	20.00	5.59	5.59
Apr-03	3.90	0.00	0.07	3.90	1.00	0.071	1.50	4.00	0.75	3.90	1.50	20.00	3.90	3.90
May-03	4.67	0.00	0.10	4.67	1.00	0.100	1.75	4.00	0.90	4.67	1.50	20.00	4.67	4.67
Jun-03	5.36	0.00	0.14	5.36	1.00	0.142	1.00	4.00	1.03	5.36	1.50	20.00	5.36	5.36
Jul-03	5.43	0.00	0.11	5.43	1.00	0.107	1.00	4.00	1.04	5.43	1.50	20.00	5.43	5.43
Aug-03	5.45	0.00	0.08	5.45	1.00	0.083	1.00	4.00	1.05	5.45	1.50	20.00	5.45	5.45
Sep-03	5.41	0.00	0.15	5.41	1.00	0.148	1.00	4.00	1.04	5.41	1.50	20.00	5.41	5.41
Oct-03	5.41	0.00	0.09	5.41	1.00	0.090	1.00	4.00	1.04	5.41	1.50	20.00	5.41	5.41
Nov-03	5.48	0.00	0.12	5.48	1.00	0.118	1.00	4.00	1.06	5.48	1.50	20.00	5.48	5.48
Dec-03	5.58	0.00	0.18	5.58	1.00	0.178	1.00	4.00	1.07	5.58	1.50	20.00	5.58	5.58
Jan-04	4.87	0.00	0.12	4.87	1.00	0.115	1.00	4.00	1.18	4.87	1.50	20.00	4.87	4.87
Feb-04	4.76	0.00	0.17	4.76	1.00	0.172	1.00	4.00	1.15	4.76	1.50	20.00	4.76	4.76
Mar-04	4.57	0.00	0.17	4.57	1.00	0.170	1.50	4.00	1.11	4.57	1.50	20.00	4.57	4.57
Apr-04	4.02	0.00	0.07	4.02	1.00	0.071	1.50	4.00	0.97	4.02	1.50	20.00	4.02	4.02
May-04	3.90	0.00	0.10	3.90	1.00	0.100	1.75	4.00	0.95	3.90	1.50	20.00	3.90	3.90
Jun-04	3.87	0.00	0.14	3.87	1.00	0.142	1.00	4.00	0.94	3.87	1.50	20.00	3.87	3.87
Jul-04	3.86	0.00	0.11	3.86	1.00	0.107	1.00	4.00	0.94	3.86	1.50	20.00	3.86	3.86
Aug-04	3.86	0.00	0.08	3.86	1.00	0.083	1.00	4.00	0.94	3.86	1.50	20.00	3.86	3.86
Sep-04	3.84	0.00	0.15	3.84	1.00	0.148	1.00	4.00	0.93	3.84	1.50	20.00	3.84	3.84
Oct-04	3.84	0.00	0.09	3.84	1.00	0.090	1.00	4.00	0.93	3.84	1.50	20.00	3.84	3.84
Nov-04	3.96	0.00	0.12	3.96	1.00	0.118	1.00	4.00	0.96	3.96	1.50	20.00	3.96	3.96
Dec-04	4.10	0.00	0.18	4.10	1.00	0.178	1.00	4.00	0.99	4.10	1.50	20.00	4.10	4.10
Jan-05	3.69	0.00	0.12	3.69	1.00	0.115	1.00	4.00	1.18	3.69	1.50	20.00	3.69	3.69
Feb-05	3.60	0.00	0.17	3.60	1.00	0.172	1.00	4.00	1.15	3.60	1.50	20.00	3.60	3.60
Mar-05	3.46	0.00	0.17	3.46	1.00	0.170	1.50	4.00	1.11	3.46	1.50	20.00	3.46	3.46
Apr-05	3.04	0.00	0.07	3.04	1.00	0.071	1.50	4.00	0.97	3.04	1.50	20.00	3.04	3.04
May-05	2.96	0.00	0.10	2.96	1.00	0.100	1.75	4.00	0.95	2.96	1.50	20.00	2.96	2.96
Jun-05	2.93	0.00	0.14	2.93	1.00	0.142	1.00	4.00	0.94	2.93	1.50	20.00	2.93	2.93
Jul-05	2.92	0.00	0.11	2.92	1.00	0.107	1.00	4.00	0.94	2.92	1.50	20.00	2.92	2.92
Aug-05	2.92	0.00	0.08	2.92	1.00	0.083	1.00	4.00	0.94	2.92	1.50	20.00	2.92	2.92
Sep-05	2.91	0.00	0.15	2.91	1.00	0.148	1.00	4.00	0.93	2.91	1.50	20.00	2.91	2.91
Oct-05	2.91	0.00	0.09	2.91	1.00	0.090	1.00	4.00	0.93	2.91	1.50	20.00	2.91	2.91
Nov-05	3.00	0.00	0.12	3.00	1.00	0.118	1.00	4.00	0.96	3.00	1.50	20.00	3.00	3.00
Dec-05	3.10	0.00	0.18	3.10	1.00	0.178	1.00	4.00	0.99	3.10	1.50	20.00	3.10	3.10

Table 6.10: Natural Gas Price Risk Model (Continued)

Jan-06	**3.98**	0.00	0.12	3.98	1.00	**0.115**	**1.00**	**4.00**	**1.18**	**3.98**	**1.50**	**20.00**	3.98	3.98
Feb-06	**3.89**	0.00	0.17	3.89	1.00	**0.172**	**1.00**	**4.00**	**1.15**	**3.89**	**1.50**	**20.00**	3.89	3.89
Mar-06	**3.74**	0.00	0.17	3.74	1.00	**0.170**	**1.50**	**4.00**	**1.11**	**3.74**	**1.50**	**20.00**	3.74	3.74
Apr-06	**3.28**	0.00	0.07	3.28	1.00	**0.071**	**1.50**	**4.00**	**0.97**	**3.28**	**1.50**	**20.00**	3.28	3.28
May-06	**3.19**	0.00	0.10	3.19	1.00	**0.100**	**1.75**	**4.00**	**0.95**	**3.19**	**1.50**	**20.00**	3.19	3.19
Jun-06	**3.16**	0.00	0.14	3.16	1.00	**0.142**	**1.00**	**4.00**	**0.94**	**3.16**	**1.50**	**20.00**	3.16	3.16
Jul-06	**3.16**	0.00	0.11	3.16	1.00	**0.107**	**1.00**	**4.00**	**0.94**	**3.16**	**1.50**	**20.00**	3.16	3.16
Aug-06	**3.16**	0.00	0.08	3.16	1.00	**0.083**	**1.00**	**4.00**	**0.94**	**3.16**	**1.50**	**20.00**	3.16	3.16
Sep-06	**3.14**	0.00	0.15	3.14	1.00	**0.148**	**1.00**	**4.00**	**0.93**	**3.14**	**1.50**	**20.00**	3.14	3.14
Oct-06	**3.14**	0.00	0.09	3.14	1.00	**0.090**	**1.00**	**4.00**	**0.93**	**3.14**	**1.50**	**20.00**	3.14	3.14
Nov-06	**3.24**	0.00	0.12	3.24	1.00	**0.118**	**1.00**	**4.00**	**0.96**	**3.24**	**1.50**	**20.00**	3.24	3.24
Dec-06	**3.35**	0.00	0.18	3.35	1.00	**0.178**	**1.00**	**4.00**	**0.99**	**3.35**	**1.50**	**20.00**	3.35	3.35

Graph 6.7: Simulated Real Delivered Natural Gas Prices for Southern California (2003 - 2006)



6.9.4 Use of Simulated Natural Gas Prices in AURORA. The impact that natural gas price risk has on HLH and LLH electricity prices are estimated in the AURORA model by inputting real monthly gas price data simulated by the Natural Gas Price Risk Model. *See* Chapter 4 of the Study, regarding the AURORA Model. From each simulation of monthly southern California natural gas prices (in real $), annual gas prices and monthly gas price ratios (monthly gas prices divided by annual gas prices) are derived. From this data, simulated monthly and annual gas prices are derived for each of the 13 regions that represent the WECC region in AURORA. This task is accomplished by adding deterministic positive/negative annual average price basis differences for each of the remaining 12 regions in AURORA to the simulated annual average delivered natural gas prices for southern California to get annual average natural gas prices for all 13 regions. Monthly natural gas prices for each of the remaining 12 regions are derived by using the simulated monthly gas price ratios for Southern California to yield monthly natural gas prices for all 13 regions. *See* Chapter 4 of the Study, regarding the AURORA Model.

6.10 CGS Nuclear Plant Performance Risk Factor

CGS Nuclear Plant generation risk is incorporated into the Risk Analysis to account for the impact that changes in CGS performance have on the amount of BPA's surplus energy revenues and power purchase expenses. CGS Nuclear Plant generation risk is modeled using the following equation:

CGS Output = (CGS capacity * H * RiskUniform(0,1))/(1+(H - 1)*RiskUniform(0,1)), where

CGS capacity = the maximum amount of output that can be produced by CGS;
H = calibration factor;

RiskUniform(0,1) = a uniform probability distribution in @RISK that samples real values between 0 and 1.

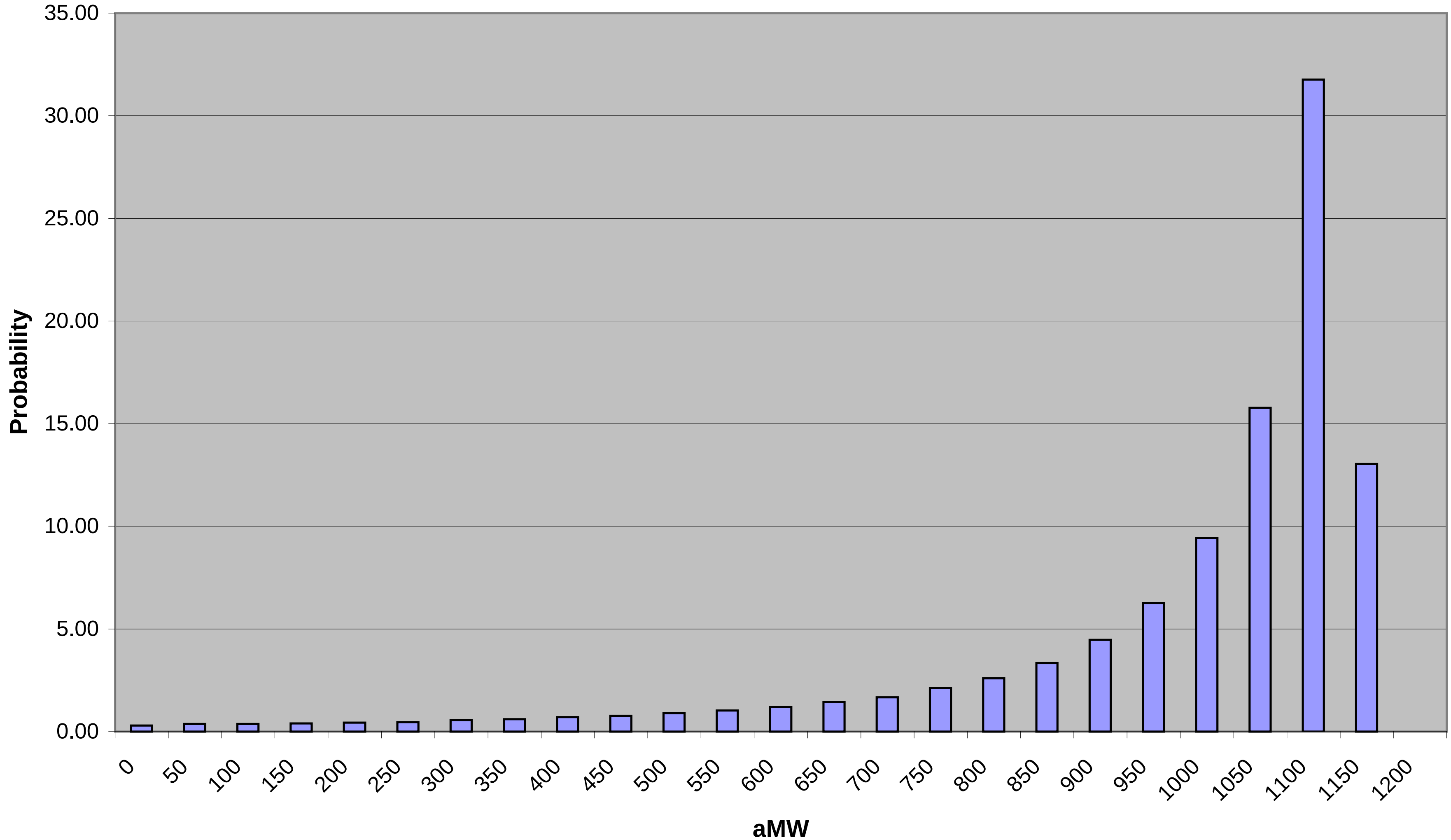
Inputs into the CGS Nuclear Plant Risk Model consist of the forecasted peak capability of CGS (1,162 MW) and expected monthly energy output reported in the Loads and Resources Study (*see* Chapter 2 of the Study). The calibration factor (H) is derived by running risk simulations and modifying the factor until the expected monthly CGS output values from the risk simulations are equal to the expected monthly values reported in the Loads and Resources Study. *Id.*

Using this equation, monthly CGS output varies from zero to peak output capability as values sampled from uniform probability distributions vary from zero to one. Although the values ranging from zero to one sampled from the uniform probability distributions are symmetrical, the frequency distribution of CGS output produced from the equation is negatively skewed with the median value (the value at the 50^{th} percentile) being higher than the average. The shape of the frequency distribution reflects that thermal plants (including CGS) typically operate at output levels higher than average output levels, but the average output is driven down by occasional forced outages in which monthly output can be substantially lower than the typical monthly output. The simulated frequency distribution for CGS output for October 2003 is shown in Graph 6.8.

6.11 Data Management Procedures

Various computer applications facilitate the movement of data between the Risk Input Data Base and RiskSim, AURORA, and RevSim. These computer applications are collectively referred to as Data Management Procedures. Of the Data Management Procedures, the principal computer program is referred to as the "Data Manager." However, other computer code (embedded in other modules of RiskMod) are components of the Data Management Procedures. This

Graph 6.8: Simulated CGS Output Distribution for October 2003



documentation of the Data Management Procedures discusses the process of inputting forecasted deterministic data and risk data simulated by RiskSim into the Risk Input Data Base, inputting data stored in the Risk Input Data Base into the AURORA Model, and downloading the results from AURORA into the Risk Input Data Base. *See* Chapter 4 of the Study, regarding the AURORA Model.

Each of these tasks is accomplished as follows. The Data Manager inputs both deterministic forecasted data and risk data simulated by RiskSim into the Risk Input Data Base. The Data Manager provides a table of PNW hydro generation values (as ratios) for each of the 50 water years that is input into the AURORA Model to estimate HLH and LLH electricity prices. Once AURORA has completed estimating HLH and LLH electricity prices for a specified number of simulations, the Data Manager downloads the prices from AURORA into the Risk Input Database.

An Excel workbook called "AURORA Link" is used to provide data from the Risk Input Data Base into AURORA so that it can estimate HLH and LLH electricity prices. Procedures in the AURORA Link workbook provide variable PNW and California hydro generation, PNW and California loads, and natural gas price data for input into AURORA (s*ee* Chapter 4 of the Study, regarding the AURORA Model) so that AURORA is able to estimate HLH and LLH electricity prices for a specified number of simulations. For each simulation, computer code housed within RevSim inputs risk data that impact net revenues. The risk data include the following: Federal hydro generation (50 water years), Federal HLH hydro generation ratio (50 water years), PNW/BPA load variability, CGS output variability, AURORA prices, and 4(h)(10)(C) purchase amounts from the Risk Input Data Base. The computer code runs RiskMod and writes the net revenue results to the Risk Output Data Base. These procedures are represented in Figure 6.1.

The computer code contained in these procedures is comprised of a combination of Microsoft Visual Basic and Structured Query Language. The Visual Basic code may appear as Visual Basic (VB) Script, Visual Basic for Applications (VBA), or VB 5.0.

The Risk Data Base is composed of one Risk Input Database and one Risk Output Database. Figure 6.2 depicts a typical Risk Input Data Base and Figure 6.3 depicts a typical Risk Output Data Base.

6.12 Loading Data

6.12.1 Forecasted Data. The data for PNW and Federal hydro generation, Federal HLH hydro generation factors, California hydro generation, and 4(h)(10)(C) purchase amounts (aMW) are considered forecasted data. Forecasted data are loaded into the Risk Input Data Base using the Data Manager. Some non-varying data, such as data from the Revenue Forecast and the Loads and Resources Study, are input directly from Excel worksheets into RevSim. Data that are entered into RevSim in this manner are not considered in this discussion.

6.12.2 Hydro Generation Data. The Data Manager is used to input monthly hydro generation data for each of the 50 water years into the Risk Input Data Base and calculate annual average hydro generation data for each calendar year.

6.12.3 4(h)(10)(C) Purchase Amounts. Power purchase amounts (monthly aMW) for the 4(h)(10)(C) calculation are input to the Risk Input Data Base using the Data Manager.

Figure 6.2: Typical Risk Input Database shown in Microsoft Access

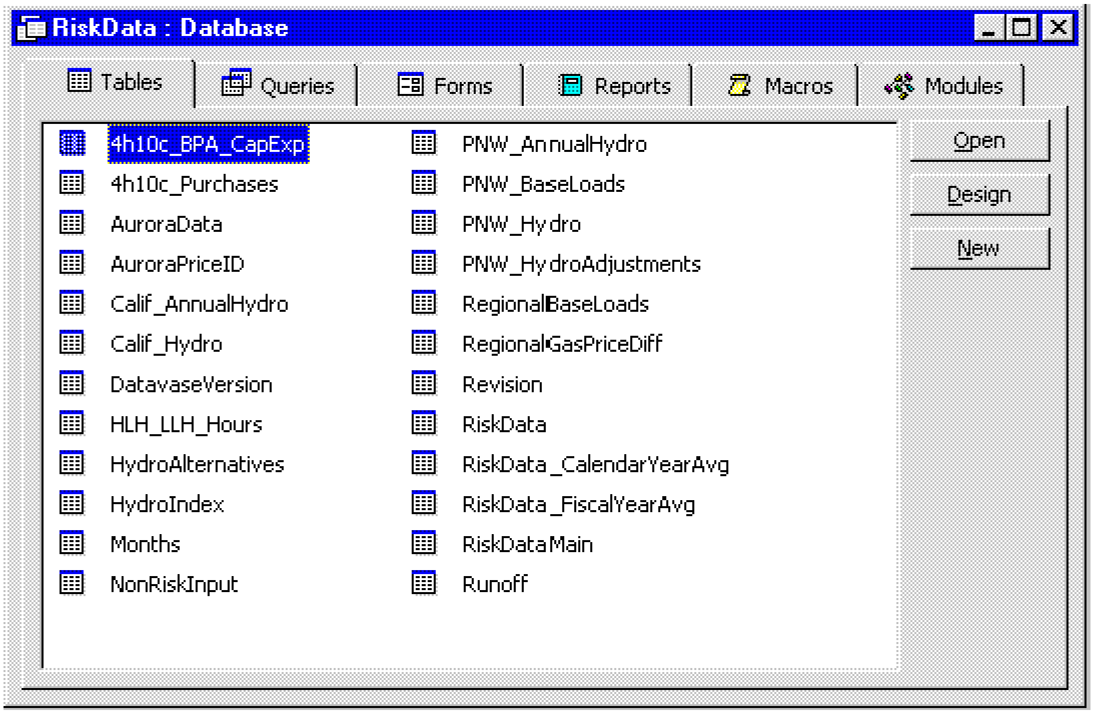
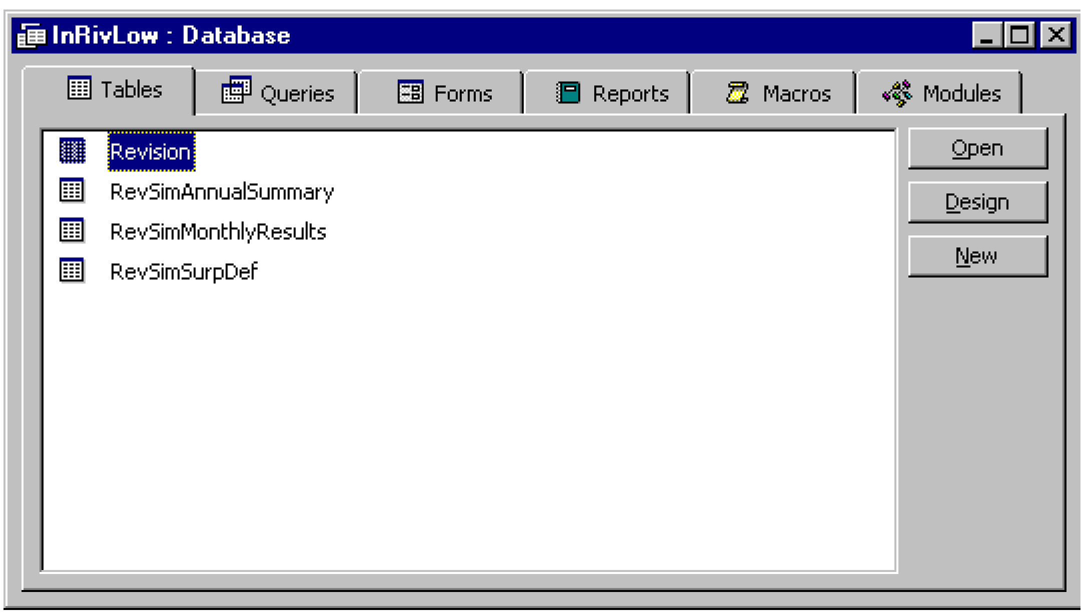


Figure 6.3: Typical Risk Output Database shown in Microsoft Access



6.13 Inputting the RiskSim Results

RiskSim is used to generate variable CGS generation, PNW/BPA and California loads, and natural gas prices. These values are combined with a random selection of PNW, Federal, and California hydro generation data. Hydro generation data used for a given simulation are defined by a "hydro index" for FY 2004-2006 and by a "refill hydro index" for FY 2003. The PNW and Federal hydro indices are represented by water years 1929-1978. The California hydro index is represented by a number from 1 to 18. This procedure is used to develop 3000 sets of 4-year outcomes of data, which are input into AURORA to estimate HLH and LLH electricity prices and input into RevSim to estimate BPA's net revenue risk.

The Data Manager loads the monthly data from the 3000 simulations into the Risk Input Data Base. Calendar year and fiscal year averages are computed for CGS, PNW loads, California loads, and natural gas prices as part of this procedure.

6.14 Interaction With the AURORA Model

AURORA uses an Access database to supply input data for each variable to its logic. The database consists of numerous tables, each containing input data. After AURORA has input data from the database and been run, the results are output to an output Access database. This process is performed using scripting, which is a VB language built into AURORA that allows the user to run AURORA commands, run the commands of other applications (*i.e.*, Excel), and to build loops to repeat procedures.

PNW hydro generation data are supplied to AURORA as monthly energy "ratios" and a 13^{th} value, which is the annual average hydro generation capacity factor. The monthly hydro generation ratios supplied to AURORA are computed by the Data Manager and written to an

Excel workbook. These monthly hydro generation ratios are computed by dividing the monthly hydro generation by the annual average hydro generation (calendar year average) for each of the 50 water years. The annual energy-to-capacity factor is calculated by dividing the PNW annual average hydro generation for each of the 50 water years (s*ee* Chapter 2 of the Study, regarding PNW hydro generation) by the PNW hydro capacity used in AURORA (*see* Chapter 4 of the Study, regarding AURORA).

The first step in preparing AURORA is to establish a link between the Access input file used by AURORA and the Excel workbook (produced by the Data Manager) that contains the monthly hydro generation ratios. This link allows AURORA to read the data that is in an Excel workbook. Second, a macro is used to alter values in the Excel workbook. Finally, a script file runs AURORA, writes the output from AURORA to an Excel workbook, revises the input data used by AURORA for the next simulation, and then runs AURORA again. The script file contains a loop that repeats this procedure 3000 times. Upon completion of this process, AURORA produces an Excel workbook containing monthly HLH and LLH electricity prices for each iteration for 4 years, which the Data Manager loads into the Risk Input Data Base.

Variation in PNW and California loads and natural gas prices are also considered along with variability in PNW and California hydro generation. An Excel workbook is used to store data for a single simulation that is refreshed with data from the Risk Input Database for each simulation. This workbook is called "AURORA Link." The AURORA Link workbook contains both VBA procedures and data for hydro generation, loads, and natural gas prices. The VBA procedures are designed so that they can be called by the VBA scripting within AURORA.

Scripting is used to call the VBA procedures in AURORA Link, run AURORA, and write HLH and LLH electricity prices to an Excel Workbook. The script file contains a loop that runs this procedure for 3000 simulations. Upon completion of the 3000 simulations, an Excel workbook receives HLH and LLH electricity prices estimated by AURORA. These HLH and LLH electricity prices are loaded into the Risk Input Data Base by the Data Manager.

6.15 Interaction with RevSim

RevSim contains VBA procedures to extract data from the Risk Input Data Base and write results to the Risk Output Data Base.

RevSim uses the following data from the Risk Input Data Base:

(1) Federal hydro generation;

(2) HLH ratios for shaping hydro generation;

(3) BPA load variability (derived from PNW load variability);

(4) CGS output;

(5) AURORA HLH and LLH prices; and

(6) 4(h)(10)(C) purchase amounts (aMW).

Surplus energy sales and purchase amounts (aMW), surplus energy revenues and power purchase expenses, and several other items to be discussed below are calculated by RiskMod and written to the Risk Output Data Base.

6.15.1 Federal HLH and LLH Hydro Generation. For a given simulation, Federal hydro generation data and HLH hydro generation ratios from the HOSS Model for FY 2004-2006 are determined by the water year sampled for the "hydro index." The hydro index is the water year to use for the first fiscal year, *i.e.*, FY 2004. Successive water years are used for each subsequent fiscal year. For example, if water year 1940 is selected as the hydro index for a given simulation, then hydro generation data for water year 1940 are used for FY 2004, hydro generation data for water year 1941 are used for FY 2005, etc. If water year 1978 is selected as the hydro index, then the data is “wrapped” to water year 1929, *i.e.*, hydro generation data for water year 1978 are used for FY 2004, hydro generation for water year 1929 are used for FY 2005, etc. Given the hydro index (water year) for a simulation, the Federal hydro generation data and HLH hydro generation ratios are retrieved from the Risk Input Data Base.

For a given simulation, Federal hydro generation data and HLH hydro generation ratios from the HOSS Model for FY 2003 are determined by the water year sampled for the “refill hydro index.” The refill hydro index is the water year to use for FY 2003. Given the refill hydro index (water year) for a simulation the Federal hydro generation data and HLH hydro generation ratios are retrieved from the Risk Input Data Base.

6.15.2 BPA Load Variability Ratios. BPA load variability ratios are calculated by dividing simulated PNW loads by the forecasted PNW loads for the corresponding month and year. These ratios are input into RevSim to modify PF loads.

6.15.3 CGS Output. Variability in CGS output is input from the Risk Input Database into RevSim. These values modify the amount of resources that BPA has available for each simulation.

6.15.4 AURORA HLH and LLH Prices. The HLH and LLH electricity prices for each simulation are read from the Risk Input Database and input into RevSim.

6.15.5 4(h)(10)(C) Purchase Amounts. The Risk Input Data Base contains the monthly amounts of 4(h)(10)(C) power purchases (aMW) for each of the 50 water years. The power purchase amounts (aMW) are read from the Risk Input Database and input into RevSim to calculate the 4(h)(10)(C) credits ($).

6.15.6 Risk Output Data Base. RiskMod produces a separate Risk Output Data Base. The Risk Output Data Base contains annual summary values data for net revenues, total revenues, 4(h)(10)(C) credits, and FCCF credits.

The Risk Output Data Base also contains monthly HLH and LLH surplus energy data (sales (aMW), prices, and revenues) and monthly HLH and LLH power purchase data (power purchases (aMW), prices, and expenses).

6.16 Operational Net Revenue Risk Analysis Model (RevSim)

RevSim is the computer model in which firm and surplus energy revenues and balancing power purchase expenses, 4(h)(10)(C) credits, and FCCF credits are calculated under various load, resource, and market price conditions to estimate BPA's operational net revenue risk. Inputs into RevSim consist of deterministic monthly load and resource data, some firm load revenues, monthly PF, IP, and RL rates, LB CRAC and FB CRAC rates, Slice Revenue Requirements, and annual expenses (other than purchase power expenses) from the Loads and Resources Study, the Revenue Recovery, and the Revenue Forecast. *See* Chapters 2, 3, and 5 of the Study.

Because RiskMod uses an aggregate load forecast, rather than individual contract details (*i.e.*, stepped rates, credits, etc) reflected in the Revenue Forecast, a calibration adjustment is made to align the deterministic revenues calculated in RiskMod with the revenues in the Revenue Forecast. Similarly, RiskMod estimates deterministic Slice revenues and revenues associated with the LB and FB CRAC which are calibrated to the revenues in the Revenue Forecast.

To quantify net revenue risk, data are input into RevSim from the Risk Input Data Base, which varies the levels of the Priority Firm (PF) loads, the output of CGS, the amount of HLH and LLH Federal hydro generation, and the HLH and LLH electricity prices from the AURORA Model.

See Chapter 4 of the Study, regarding the AURORA Model. Using this data, net revenues are calculated for each simulation.

6.17 Details of RevSim Modeling

6.17.1 Loads and Resources. A key attribute of RevSim is that it is a HLH and LLH loads and resources model. For each simulation, it estimates BPA's HLH and LLH load and resource condition. All the HLH and LLH load and resource data used in RevSim are obtained from the Loads and Resources Study. *See* Chapter 2 of the Study. The shaping of hydro generation into HLHs is measured as a ratio relative to average energy. These HLH ratios are obtained from a computer run of HOSS. *See* Hydro Regulation component of the Loads and Resources Study (Chapter 2 of the Study), regarding HOSS. The HLH shaping ratios from HOSS are multiplied by average monthly hydro generation data for each of the 50 water years from the Hydro regulation component of the Loads and Resources Study.   *See* Hydro Regulation component of the Loads and Resources Study (Chapter 2 of the Study). Given the ratios for the HLH shaping of hydro generation, the ratios for the LLH shaping of hydro generation are computed in RevSim.

All the risk data, with the exception of PF load variability, are input into RevSim as values. PF load variability is quantified as ratios relative to 1.00. These load variability ratios are multiplied by the forecasted monthly PF loads subject to the load variance charge. The differences between the simulated and forecasted values are added to the forecasted monthly PF loads in the Revenue Forecast to obtain variable PF loads**.** This calculation is reflected in the following equation: Simulated PF load = Forecasted PF load + (PF (LV) load * Ratio) - PF (LV) load), where PF (LV) load is the amount of PF load subject to the load variance charge.

These variable PF loads are used to compute variable full and partial requirements customer energy revenues. In addition to adjusting PF loads (energy), the ratios (relative to 1.00) are multiplied by the forecasted monthly PF demand in the Revenue Forecast to obtain variable PF demand. These variable demand values are used to compute variable full and partial requirements customers demand revenues.

The impact to the Slice product on surplus energy sales and balancing power purchases is calculated in RevSim. The load impact is included in the load data received from the Loads and Resources Study. *See* Chapter 2 of the Study. The resource impact is quantified by modeling the Slice share of Federal hydro generation and the output from the Columbia Generating Station (CGS), decremented for certain system obligations which are not subject to Slice. The Slice share used in this proposal is 22.7 percent. The 22.7 percent of the resources was derived by dividing 1,604 aMW of Slice by the Slice Total System Inventory of 7,070 aMW.

Transmission losses are incorporated into RevSim by reducing Federal hydro generation and CGS output by 2.82 percent. The 2.82 percent loss factor represents the transmission losses on BPA's transmission system, excluding losses on the Southern Intertie. This loss factor is identical to the loss factor used in the Loads and Resources Study. *See* Hydro Regulation component of the Loads and Resources Study (Chapter 2 of the Study).

In addition to the resources in the Loads and Resources Study, RevSim includes logic that reflects Non-Treaty Storage operations. BPA's ability to store and remove energy from Non-Treaty Storage is modeled via an algorithm. The parameters in the Non-Treaty Storage algorithm are the total amount of energy that can be stored, the beginning Non-Treaty Storage level, and monthly maximum and minimum storage and release constraints.

The algorithm tracks the level of Non-Treaty Storage from month to month and stores and releases energy within operational constraints. Non-Treaty Storage is modeled to have first call on all surplus energy and is withdrawn before any power purchases are made. The storage and withdrawal decisions for Non-Treaty Storage are based on average monthly energy surplus and deficit values.

Non-Treaty Storage operations were not model in RevSim for FY 2003 because they were reflected in the FY 2003 Federal hydro generation data. *See* Hydro Regulation component of the Loads and Resources Study (Chapter 2 of the Study).

Non-Treaty Storage operations for FY 2004-2006 were modeled in RevSim. The starting FY 2004 Non-Treaty Storage balance in RevSim was set to 1470 MW-Mo to reflect the forecasted expected Non-Treaty Storage level at the end of FY 2003 and a maximum Non-Treaty Storage level limit of 2,800 MW-Mo was used for FY 2004-2006, which is less than total Non-Treaty Storage of 4,763 MW-Mo. With the cap of 2,800 MW-Mo, expected Non-Treaty storage levels at the beginning of each Fiscal Year were about 2,000 MW-Mo. A copy of the Non-Treaty Storage algorithm and an example of how it works during FY 2003-2006 is provided in Table 6.11.

Table 6.11: Example of Non-Treaty Storage Operations for FY 2003 - FY 2006

Non-Treaty Storage Operation (FY 2003)

The Hydroregulation Study for FY 2003 Included NTS Operation

Total Non-Treaty Storage Available to BPA (MW-Mo)	2800
Non-Treaty Storage H/K (Currently Not Being Used)	145
Initial, Beginning of the Month, Non-Treaty Storage Level (MW-Mo)	**1470**
Month of Beginning Non-Treaty Storage Level (MW-Mo); (Oct = 1)	**1**

	Oct '02	Nov '02	Dec '02	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	Jul '03	Aug '03	Sep '03
Monthly Maximum Storage Constraints (MW-Mo)	675	675	1350	1350	1350	675	270	675	675	0	0	675
Monthly Maximum Release Constraints (MW-Mo)	675	675	270	675	675	675	0	0	0	675	675	675
Month Number	1	2	3	4	5	6	7	8	9	10	11	12
Beginning Monthly Non-Treaty Storage Balance (MW-Mo)	**1470**	**1470**	**1470**	**1470**	**1470**	**1470**	**1470**	**1470**	**1470**	**1470**	**1470**	**1470**
Amount of Remaining Storage (MW-Mo)	1330	1330	1330	1330	1330	1330	1330	1330	1330	1330	1330	1330
BPA Monthly Surpluses/Deficits	-5635	-6701	-7287	-6684	-6171	-6730	1200	1127	2798	3579	1566	792

Storage Transactions:

	Oct '02	Nov '02	Dec '02	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	Jul '03	Aug '03	Sep '03
BPA Deficit Amount	-5635	-6701	-7287	-6684	-6171	-6730	0	0	0	0	0	0
Energy Released From NTS	0	0	0	0	0	0	0	0	0	0	0	0
BPA Surplus Amount	0	0	0	0	0	0	1200	1127	2798	3579	1566	792
Energy Stored in NTS	0	0	0	0	0	0	0	0	0	0	0	0
Ending Monthly Non-Treaty Storage Balance (MW-Mo)	1470	1470	1470	1470	1470	1470	1470	1470	1470	1470	1470	1470

Results

	Oct '02	Nov '02	Dec '02	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	Jul '03	Aug '03	Sep '03
Non-Treaty Storage Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Table 6.11: Example of Non-Treaty Storage Operations for FY 2004 (Continued)

Non-Treaty Storage Operation (FY 2004)

NOTE: Logic for July and August forces release of Non-Treaty Storage to comport with fish operations for these months

	Oct '03	Nov '03	Dec '03	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	Jul '04	Aug '04	Sep '04
Monthly Maximum Storage Constraints (MW-Mo)	675	675	1350	1350	1350	675	270	675	675	0	0	675
Monthly Maximum Release Constraints (MW-Mo)	675	675	270	675	675	675	0	0	0	675	675	675
Month Number	1	2	3	4	5	6	7	8	9	10	11	12
Beginning Monthly Non-Treaty Storage Balance (MW-Mo)	**1470**	2145	2800	2800	2800	2800	2800	2800	2800	2800	2125	1450
Amount of Remaining Storage (MW-Mo)	1330	655	0	0	0	0	0	0	0	0	675	1350
BPA Monthly Surpluses/Deficits	1509	1438	560	4022	1997	5178	4056	5957	4404	5624	1856	469

Storage Transactions:

	Oct '03	Nov '03	Dec '03	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	Jul '04	Aug '04	Sep '04
BPA Deficit Amount	0	0	0	0	0	0	0	0	0	0	0	0
Energy Released From NTS	0	0	0	0	0	0	0	0	0	675	675	0
BPA Surplus Amount	1509	1438	560	4022	1997	5178	4056	5957	4404	5624	1856	469
Energy Stored in NTS	675	655	0	0	0	0	0	0	0	0	0	469
Ending Monthly Non-Treaty Storage Balance (MW-Mo)	2145	2800	2800	2800	2800	2800	2800	2800	2800	2125	1450	1919

Results

	Oct '03	Nov '03	Dec '03	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	Jul '04	Aug '04	Sep '04
Non-Treaty Storage Transactions	**675**	**655**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-675**	**-675**	**469**

Table 6.11: Example of Non-Treaty Storage Operations for FY 2005 (Continued)

Non-Treaty Storage Operation (FY 2005)

NOTE: Logic for July and August forces release of Non-Treaty Storage to comport with fish operations for these months

	Oct '04	Nov '04	Dec '04	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	Jul '05	Aug '05	Sep '05
Monthly Maximum Storage Constraints (MW-Mo)	675	675	1350	1350	1350	675	270	675	675	0	0	675
Monthly Maximum Release Constraints (MW-Mo)	675	675	270	675	675	675	0	0	0	675	675	675
Month Number	1	2	3	4	5	6	7	8	9	10	11	12
Beginning Monthly Non-Treaty Storage Balance (MW-Mo)	**1919**	2594	2800	2800	2800	2125	2518	2518	2518	2800	2125	1450
Amount of Remaining Storage (MW-Mo)	881	206	0	0	0	675	282	282	282	0	675	1350
BPA Monthly Surpluses/Deficits	1361	1166	535	1393	-976	393	-436	-442	1616	2959	2836	726

Storage Transactions:

	Oct '04	Nov '04	Dec '04	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	Jul '05	Aug '05	Sep '05
BPA Deficit Amount	0	0	0	0	-976	0	-436	-442	0	0	0	0
Energy Released From NTS	0	0	0	0	675	0	0	0	0	675	675	0
BPA Surplus Amount	1361	1166	535	1393	0	393	0	0	1616	2959	2836	726
Energy Stored in NTS	675	206	0	0	0	393	0	0	282	0	0	675
Ending Monthly Non-Treaty Storage Balance (MW-Mo)	2594	2800	2800	2800	2125	2518	2518	2518	2800	2125	1450	2125

Results

	Oct '04	Nov '04	Dec '04	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	Jul '05	Aug '05	Sep '05
Non-Treaty Storage Transactions	**675**	**206**	**0**	**0**	**-675**	**393**	**0**	**0**	**282**	**-675**	**-675**	**675**

Table 6.11: Example of Non-Treaty Storage Operations for FY 2006 (Continued)

Non-Treaty Storage Operation (FY 2006)

NOTE: Logic for July and August forces release of Non-Treaty Storage to comport with fish operations for these months

	Oct '05	Nov '05	Dec '05	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06
Monthly Maximum Storage Constraints (MW-Mo)	675	675	1350	1350	1350	675	270	675	675	0	0	675
Monthly Maximum Release Constraints (MW-Mo)	675	675	270	675	675	675	0	0	0	675	675	675
Month Number	1	2	3	4	5	6	7	8	9	10	11	12
Beginning Monthly Non-Treaty Storage Balance (MW-Mo)	**2125**	2800	2800	2800	2125	1798	1387	1387	1387	2062	1387	712
Amount of Remaining Storage (MW-Mo)	675	0	0	0	675	1002	1413	1413	1413	738	1413	2088
BPA Monthly Surpluses/Deficits	1604	1289	305	-1435	-327	-411	-47	-155	2213	2874	1528	298

Storage Transactions:

	Oct '05	Nov '05	Dec '05	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06
BPA Deficit Amount	0	0	0	-1435	-327	-411	-47	-155	0	0	0	0
Energy Released From NTS	0	0	0	675	327	411	0	0	0	675	675	0
BPA Surplus Amount	1604	1289	305	0	0	0	0	0	2213	2874	1528	298
Energy Stored in NTS	675	0	0	0	0	0	0	0	675	0	0	298
Ending Monthly Non-Treaty Storage Balance (MW-Mo)	2800	2800	2800	2125	1798	1387	1387	1387	2062	1387	712	1010

Results

	Oct '05	Nov '05	Dec '05	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06
Non-Treaty Storage Transactions	**675**	**0**	**0**	**-675**	**-327**	**-411**	**0**	**0**	**675**	**-675**	**-675**	**298**

6.17.2 Surplus Energy Sales and Revenues. After computing all monthly HLH and LLH loads and resources, including Slice and storage into Non-Treaty Storage, when the Federal System has surplus energy, RevSim sells all the surplus energy at the HLH and LLH electricity prices estimated by AURORA. Tables 6.12 and 6.13 contain statistical information on the FY 2003-2006 annual surplus energy sales and revenues computed by RevSim.

6.17.3 Power Purchases and Expenses. After computing all monthly HLH and LLH loads and resources, including Slice and withdrawal from Non-Treaty Storage, when the Federal System is deficit, RevSim purchases the energy deficit at the HLH and LLH electricity prices estimated by AURORA. Tables 6.14 and 6.15 contain statistical information on the FY 2003-2006 annual power purchases and expenses computed by RevSim.

6.17.4 4(h)(10)(C) Credits. The 4(h)(10)(C) credit is a provision in the 1980 Pacific Northwest Electric Power Planning and Conservation Act that allows BPA and its ratepayers to receive a credit for non-power fish and wildlife costs attributable to the Federal projects. The amount of 4(h)(10)(C) credits that BPA can collect for each of the 50 water years for FY 2003-2006 is determined by summing the costs of the operational impacts, the expenses, and the capital costs associated with fish and wildlife mitigation measures, and then multiplying the total cost by 22.3 percent.

The costs of the operational portion of the 4(h)(10)(C) credits were calculated for each of the 50 water years in RiskMod for FY 2004-2006 by multiplying HLH and LLH electricity prices from AURORA by the amount of power purchases (aMW) that qualifies for 4(h)(10)(C) credits. For FY 2003, the operational portion of the 4(h)(10)(C) credits were computed for each of the 50 water years in RiskMod by multiplying the amount of power purchases (aMW) that qualifies for 4(h)(10)(C) credits by actual Mid-C prices for October through March and AURORA prices for April through September. Since the operational portion of the credit is impacted by the power

Table 6.12: Forecasted Surplus Sales (aMW)					
	FY 2003	**FY 2004**	**FY 2005**	**FY 2006**	**4 Yr Average**
Average	550	2,551	2,501	2,392	1,998
Median	500	2,577	2,517	2,406	
StDev	178	957	974	951	
1% <=	169	732	712	656	
2.5% <=	203	792	755	706	
5% <=	295	857	830	778	
10% <=	343	1,009	975	929	
15% <=	369	1,426	1,348	1,229	
20% <=	396	1,626	1,581	1,505	
25% <=	423	1,925	1,811	1,725	
30% <=	438	2,135	2,018	1,890	
35% <=	452	2,293	2,179	2,049	
40% <=	466	2,403	2,310	2,190	
45% <=	483	2,492	2,417	2,302	
50% <=	500	2,577	2,516	2,405	
55% <=	540	2,684	2,630	2,533	
60% <=	619	2,791	2,769	2,653	
65% <=	664	2,932	2,914	2,777	
70% <=	690	3,065	3,040	2,911	
75% <=	711	3,205	3,194	3,072	
80% <=	732	3,405	3,433	3,281	
85% <=	752	3,687	3,650	3,521	
90% <=	776	3,854	3,844	3,706	
95% <=	812	4,107	4,058	3,944	
97.5% <=	844	4,240	4,208	4,080	
99% <=	906	4,367	4,307	4,204	

Table 6.13: Forecasted Surplus Sales Revenues ($ Thousand)					
	FY 2003	**FY 2004**	**FY 2005**	**FY 2006**	**4 Yr Average**
Average	226,691	644,381	526,461	505,336	475,717
Median	216,184	639,208	528,432	505,257	
StDev	83,320	226,845	186,449	179,378	
1% <=	73,018	212,324	174,395	165,948	
2.5% <=	87,089	248,599	196,864	191,161	
5% <=	103,191	290,310	222,957	210,394	
10% <=	125,684	341,039	262,944	253,747	
15% <=	142,857	392,513	310,840	305,417	
20% <=	155,071	445,649	357,570	345,648	
25% <=	164,215	482,406	394,559	381,567	
30% <=	174,455	516,767	426,703	408,582	
35% <=	184,223	547,370	455,511	434,537	
40% <=	193,762	577,514	480,187	458,272	
45% <=	205,126	609,040	504,006	481,274	
50% <=	216,177	639,084	528,260	505,243	
55% <=	227,702	666,314	551,369	527,738	
60% <=	239,671	693,611	573,302	548,884	
65% <=	253,496	722,279	596,123	571,303	
70% <=	266,571	754,961	623,123	594,883	
75% <=	284,043	793,089	647,871	623,618	
80% <=	301,150	836,115	678,594	654,137	
85% <=	318,963	884,474	722,116	690,590	
90% <=	341,857	934,951	771,107	736,183	
95% <=	376,091	1,024,841	841,760	811,084	
97.5% <=	407,234	1,121,028	904,806	870,674	
99% <=	430,342	1,233,621	977,635	946,258	

Table 6.14: Forecasted Power Purchases (aMW)					
	FY 2003	FY 2004	FY 2005	FY 2006	4 Yr Average
Average	39	17	25	49	32
Median	18	2	0	15	
StDev	45	30	44	70	
1% <=	0	0	0	0	
2.5% <=	0	0	0	0	
5% <=	0	0	0	0	
10% <=	0	0	0	0	
15% <=	0	0	0	0	
20% <=	0	0	0	0	
25% <=	1	0	0	2	
30% <=	4	0	0	4	
35% <=	8	0	0	5	
40% <=	12	0	0	7	
45% <=	15	1	0	10	
50% <=	18	2	0	15	
55% <=	22	4	2	19	
60% <=	34	6	7	24	
65% <=	49	9	10	31	
70% <=	55	14	15	48	
75% <=	61	20	25	71	
80% <=	76	30	47	106	
85% <=	97	43	72	131	
90% <=	108	62	95	160	
95% <=	125	87	126	198	
97.5% <=	153	108	150	234	
99% <=	176	128	183	280	

Table 6.15: Forecasted Power Purchase Expenses ($ Thousand)					
	FY 2003	**FY 2004**	**FY 2005**	**FY 2006**	**4 Yr Average**
Average	16,374	7,657	8,365	17,388	12,446
Median	6,026	811	34	4,096	
StDev	20,708	14,018	16,530	27,508	
1% <=	0	0	0	0	
2.5% <=	0	0	0	0	
5% <=	0	0	0	0	
10% <=	0	0	0	0	
15% <=	0	0	0	0	
20% <=	0	0	0	0	
25% <=	407	0	0	478	
30% <=	1,361	0	0	1,100	
35% <=	2,574	0	0	1,670	
40% <=	3,698	0	0	2,229	
45% <=	4,778	304	0	3,046	
50% <=	6,006	808	34	4,094	
55% <=	7,940	1,553	671	5,531	
60% <=	12,774	2,509	1,990	7,330	
65% <=	17,328	3,916	3,234	9,964	
70% <=	21,070	6,220	5,125	15,122	
75% <=	25,357	9,179	7,964	23,680	
80% <=	32,827	12,934	14,645	33,841	
85% <=	41,288	18,561	21,569	44,387	
90% <=	48,435	26,125	30,522	56,769	
95% <=	59,231	38,171	42,824	75,349	
97.5% <=	69,388	47,480	55,222	92,832	
99% <=	80,773	59,842	68,386	117,706	

purchase amount (aMW) needed for each water condition, the 4(h)(10)(C) credits for FY 2003 were affected by the water year weights used for FY 2003. The amounts of power purchases (aMW) that qualifies for 4(h)(10)(C) credits is derived external to RevSim, but are used in RevSim to calculate the dollar amount of the 4(h)(10)(C) credits. *See* Loads and Resources Study (Chapter 2 of the Study), regarding the amounts of power purchases (aMW) that qualify for 4(h)(10)(C) credits.

The capital costs used in RevSim for FY 2003-2006 are $12.0, $36.0, $36.0, and $36.0 million and the expenses are $151.0, $139.0, $139.0, and $139.0 million. Statistical information on the 4(h)(10)(C) credits, by Fiscal Year, are reported in Table 6.16.

6.17.5 FCCF. The FCCF credit is related to the 4(h)(10)(C) credit. It is an agreement between BPA and the Office of Management and Budget implemented to allow BPA and its ratepayers to obtain limited credit for non-power fish and wildlife costs that occurred prior to 1995. The original amount of the FCCF reserve was $325 million. The remaining amount of this reserve, after BPA claimed $246 million in FCCF credits in FY 2001, is $79 million. The amount of annual FCCF credits that BPA can claim, if there were no limitations in the reserve balance of the FCCF, for each of the 50 water years for FY 2003-2006 are calculated external to RevSim. These values were calculated in a spreadsheet using monthly surplus energy revenues and power purchase expenses for each of the 50 water years, with the FY 2003 credits reflecting revised estimates based on both actual and forecasted streamflow and price data. The calculations in the spreadsheet produce a 50 (50 water years) X 4 (FY 2003-2006) table of annual FCCF credits that were input into RevSim. The 50 X 4 matrices of FCCF credits for FY 2003-2006 are reported in Table 6.17. A description of the FCCF and the process used to calculate the credits are reported in the 2002 Final Power Rate Proposal, May 2000, Revenue Requirement Study Documentation, WP-02-E-BPA-02A.

Table 6.16: 4(h)(10)(c) Credit Statistics ($ Thousand)				
	FY 2003	**FY 2004**	**FY 2005**	**FY 2006**
Average	104,566	77,034	67,459	66,350
Median	104,898	68,695	60,626	58,087
StDev	6,285	29,303	22,925	23,383
1% <=	92,580	37,873	37,973	37,881
2.5% <=	93,345	38,659	37,973	37,955
5% <=	94,025	42,118	40,708	40,450
10% <=	95,044	46,500	43,981	43,191
15% <=	95,858	51,317	47,616	46,741
20% <=	100,121	55,295	50,329	49,038
25% <=	101,289	57,924	52,356	50,783
30% <=	101,970	60,036	53,852	52,327
35% <=	102,720	62,080	55,270	53,540
40% <=	103,613	64,079	56,939	54,981
45% <=	104,323	66,190	58,735	56,439
50% <=	104,897	68,688	60,620	58,085
55% <=	105,414	71,416	62,783	60,456
60% <=	105,976	74,375	65,346	62,939
65% <=	106,520	77,843	68,290	66,421
70% <=	107,204	82,494	72,266	70,965
75% <=	108,195	89,671	77,290	76,336
80% <=	109,335	97,849	83,480	84,021
85% <=	110,893	107,946	91,818	93,141
90% <=	112,381	120,908	103,263	103,419
95% <=	114,557	139,061	115,695	116,300
97.5% <=	117,307	153,227	126,510	125,642
99% <=	120,782	165,282	137,157	135,195

Table 6.17: Annual FCCF Credit Algorithm ($ Million)

Beginning Reserve Balance	79.0	**79.0**	**Ending Reserve Level**
Credit for Fiscal year '02 :	0.0	**79.0**	
Credit for Fiscal year '03 :	79.0	**0.0**	
Credit for Fiscal year '04 :	0.0	**0.0**	
Credit for Fiscal year '05 :	0.0	**0.0**	
Credit for Fiscal year '06 :	0.0	**0.0**	

Note: Beginning Reserve Balance Reflects Potential Reserve Reductions during FY2001

Water Year	**Reserves Beginning FY02**	**FY 02**	**FY 03**	**FY 04**	**FY 05**	**FY 06**
1929	**79.00**	0.00	285.70	355.19	367.04	391.77
1930	**79.00**	0.00	277.88	352.59	379.79	401.18
1931	**79.00**	0.00	418.30	458.40	451.51	485.82
1932	**79.00**	0.00	13.09	170.85	186.12	205.24
1933	**79.00**	0.00	0.00	0.00	0.00	0.00
1934	**79.00**	0.00	89.32	0.00	0.00	0.00
1935	**79.00**	0.00	139.87	0.00	0.00	0.00
1936	**79.00**	0.00	115.93	168.33	153.32	181.47
1937	**79.00**	0.00	261.69	409.54	437.21	459.30
1938	**79.00**	0.00	18.13	11.07	9.34	20.71
1939	**79.00**	0.00	200.20	133.64	139.55	153.04
1940	**79.00**	0.00	228.28	148.75	150.80	178.42
1941	**79.00**	0.00	306.24	266.89	288.40	315.09
1942	**79.00**	0.00	138.88	0.00	0.00	0.00
1943	**79.00**	0.00	0.00	0.00	0.00	0.00
1944	**79.00**	0.00	352.92	378.71	402.85	438.70
1945	**79.00**	0.00	186.68	312.86	330.44	349.63
1946	**79.00**	0.00	0.00	0.00	0.00	0.00
1947	**79.00**	0.00	39.17	0.00	0.00	0.00
1948	**79.00**	0.00	0.00	0.00	0.00	0.00
1949	**79.00**	0.00	58.96	68.74	52.15	93.19
1950	**79.00**	0.00	0.00	0.00	0.00	0.00
1951	**79.00**	0.00	0.00	0.00	0.00	0.00
1952	**79.00**	0.00	0.00	0.00	0.00	0.00
1953	**79.00**	0.00	37.43	0.00	0.00	0.00
1954	**79.00**	0.00	0.00	0.00	0.00	0.00
1955	**79.00**	0.00	54.81	0.00	0.00	0.00
1956	**79.00**	0.00	0.00	0.00	0.00	0.00
1957	**79.00**	0.00	0.00	0.00	0.00	0.00
1958	**79.00**	0.00	29.54	0.00	0.00	0.00
1959	**79.00**	0.00	0.00	0.00	0.00	0.00
1960	**79.00**	0.00	64.85	0.00	0.00	0.00
1961	**79.00**	0.00	8.68	0.00	0.00	0.00
1962	**79.00**	0.00	78.59	0.00	0.00	0.00
1963	**79.00**	0.00	145.59	0.00	0.00	0.00
1964	**79.00**	0.00	0.00	0.00	0.00	0.00
1965	**79.00**	0.00	0.00	0.00	0.00	0.00
1966	**79.00**	0.00	145.04	0.00	0.00	0.00
1967	**79.00**	0.00	0.00	0.00	0.00	0.00
1968	**79.00**	0.00	152.65	0.00	0.00	0.00
1969	**79.00**	0.00	0.00	0.00	0.00	0.00
1970	**79.00**	0.00	120.51	0.00	0.00	0.00
1971	**79.00**	0.00	0.00	0.00	0.00	0.00
1972	**79.00**	0.00	0.00	0.00	0.00	0.00
1973	**79.00**	0.00	302.56	131.87	132.75	145.13
1974	**79.00**	0.00	0.00	0.00	0.00	0.00
1975	**79.00**	0.00	0.00	0.00	0.00	0.00
1976	**79.00**	0.00	0.00	0.00	0.00	0.00
1977	**79.00**	0.00	404.26	368.44	394.04	427.02
1978	**79.00**	0.00	52.23	0.00	0.00	0.00
AVERAGE	**79.0**	**0.0**	**94.6**	**74.7**	**77.5**	**84.9**

The FCCF credits for each of the 50 water years, given the limitation in the FCCF reserve balance of $79 million, are determined by running RiskMod. These FCCF values are determined by inputting into RevSim the annual FCCF credits for each of the 50 water years for FY 2003-2006, inputting the FCCF reserve balance of $79 million at the beginning of FY 2003, and running RiskMod. Since the FCCF credit is affected by the water year for each simulation, the FCCF credit for FY 2003 is affected by the water year weights used for FY 2003. Statistical information on the FCCF credits, by Fiscal Year, are reported in Table 6.18.

6.18 Results from RiskMod

Table 6.19 contains detailed statistical information about the net revenue distributions from RiskMod for FY 2003-2006. These net revenues reflect revenues from the LB CRAC rate and FB CRAC rate (the FB CRAC is assumed to trigger by the full amount in all FYs), but do not reflect revenues from the SN CRAC rate, which is computed in the ToolKit Model. *See* Chapter 7 of the Study, regarding the ToolKit Model. Tables 6.20 through 6.55 contain detailed monthly statistics on HLH and LLH surplus energy sales, surplus energy revenues, power purchases, and power purchase expenses.